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November 23, 2016

VIA EMAIL AND FEDEX

Mr. Ron Curry
Regional Administrator
U.S. Environmental Protection Agency
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Dallas, TX 75202-2733

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Re: Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc. et al. of the Arkansas Regional Haze and Interstate Visibility Transport Federal Implementation Plan, EPA Docket No. EPA-R06-OAR-2015-0189

Dear Administrator Curry:

Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power, LLC (collectively "Entergy") respectfully submit the enclosed Petition for Reconsideration and Request for Stay ("Petition") of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("Final FIP"). 81 Fed. Reg. 66,332 (Sept. 27, 2016).

The Petition includes exhibits that contain Confidential Business Information for Entergy and for a third party. The exhibits have been partially redacted to remove non-pertinent information and are clearly marked as "Redacted and Confidential Business Information." Entergy also is providing a copy of the exhibits without the aforementioned confidential exhibits. Due to their length, both versions of the exhibits to the Petition are being provided on the enclosed CDs. An additional copy of the Petition is enclosed to be time-stamped and returned in the attached envelope.

Thank you for your consideration of the enclosed Petition for Reconsideration and Request for Stay. If you have any questions, please contact me at (202) 639-7728.

Sincerely,

Debra Jezouit

Debra J. Jezouit
Counsel to Entergy Services Inc.

Enclosures

cc: The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

In re:	)	EPA Docket No.
	)	
Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan	)))))	EPA-R06-OAR-2015-0189

Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., et al., of the Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

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Entergy Arkansas Inc. ("EAI"), Entergy Mississippi Inc. ("EMI"), and Entergy Power, LLC (collectively "Entergy") respectfully submit this petition for reconsideration and request for stay ("Petition") of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("Final FIP").[1] As discussed below, Entergy requests that EPA reconsider and stay elements of the Final FIP that relate to Entergy's White Bluff and Independence plants. To avoid the significant, irreparable harms that already have begun to occur, Entergy respectfully requests that EPA take action on this Petition by February 1, 2017. The administrative stay requested by Entergy would not cause adverse visibility impacts in Arkansas' Class I areas.

I. INTRODUCTION AND SUMMARY

The Final FIP affects four coal-fired electric generating units owned by Entergy: two at the White Bluff Electric Power Plant ("White Bluff") and two at the Independence Steam Electric Station ("Independence"), which will impose costs on Entergy, its co-owners and its customers of approximately $2 billion for minimal visibility benefits. Specifically, the Final FIP requires each coal-fired unit at White Bluff and Independence to meet a sulfur dioxide ("SO_2") emission limit of 0.06 lb/MMBtu by October 27, 2021.[2] This emission limit is based on the installation of a dry scrubber (flue gas desulfurization ("FGD") technology) on each unit. The Final FIP also will require each coal-fired unit to meet a nitrogen oxides ("NOx") emission limit of 0.15 lb/MMBtu on a rolling 30-boiler operating day basis at loads of 50-100 percent of maximum heat input rating, and a rolling 3-hour average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating.[3] These emission limits, which must be met beginning

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[1] 81 Fed. Reg. 66,332 (Sept. 27, 2016).
[2] *Id.* at 66,339, 66,416, 66,420.
[3] *Id.* at 66,416-17.

April 27, 2018, are based on the installation of low-NOx burners and separated overfire air ("LNB/SOFA") on each unit.

The Petition must be granted because EPA failed to provide adequate notice and opportunity to comment on significant, burdensome requirements in the Final FIP that affect the requirements imposed on Entergy's units, are of central relevance to the outcome of the Final FIP, and are not logical outgrowths of the proposed rule ("Proposed FIP").[4] Additionally, the Final FIP contains clear errors that must be corrected. These administrative shortcomings demand reconsideration and a stay of key elements of the Final FIP. Specifically, Entergy requests that EPA reconsider the following:

- the imposition of reasonable progress controls on Independence;
- EPA's determination that dry FGD technology constitutes best available retrofit technology ("BART") for White Bluff for SO_2 emissions;
- the 18-month deadline for installation of NOx controls at White Bluff and Independence;
- the adoption of source-specific NOx BART in lieu of reliance on the emissions reductions resulting from implementation of the Cross-State Air Pollution Rule ("CSAPR");[5] and
- the NOx limit and three-hour averaging period for NOx compliance that applies when units at White Bluff and Independence operate at low loads.

A stay of certain requirements in the Final FIP is necessary because justice so requires and to avoid irreparable harm to Entergy and its co-owners, customers, and communities while EPA reconsiders the Final FIP, and while the U.S. Court of Appeals for the Eighth Circuit ("Eighth Circuit") considers Entergy's petition for review of those requirements.[6] The pollution controls at White Bluff and Independence required by the Final FIP would cost approximately *$2 billion* to design, permit, purchase, and install. Absent a stay, Entergy will be forced to make a costly Hobson's choice: (1) commence designing, permitting, purchasing, and installing the required controls immediately; or (2) commence planning to decommission White Bluff and Independence by the Final FIP compliance deadline in 2021. Either course of action causes irreparable harm. The first option would require Entergy to expend $150 million or more just within the next 18 months that could be rendered entirely unnecessary by a grant of reconsideration. The second option would require an array of costly steps planning for decommissioning the units and would ultimately lead to a host of significant harms to Entergy and its co-owners, customers, and local economies. Furthermore, Entergy could not avoid these harms by changing course at a later date, because it will either already have expended multiple millions of dollars on equipment that will serve no purpose (if it initially selected the first option), or it will be too late to install the controls in time to meet the deadline (if it initially selected the second option).

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[4] 80 Fed. Reg. 18,944 (Apr. 8, 2015).

[5] *See* Petition for Reconsideration and Request for Administrative Stay of Arkansas Department of Environmental Quality, at 5-8 (Nov. 22, 2016) (hereinafter "ADEQ Petition").

[6] Specifically, Entergy seeks a stay of 40 C.F.R. §§ 52.173(c)(6)-(8) with respect to White Bluff and §§ 52.173(c)(24)-(26) with respect to Independence.

A stay would avoid irreparable harm yet would have no adverse impact on visibility in either Arkansas Class I area, as monitoring data show that current visibility already is better than the reasonable progress goals ("RPGs") established by EPA for this implementation period and that visibility in the Class I areas continues to improve.

Immediate action on this Petition is urgently needed to avoid the harms described herein. Therefore, Entergy respectfully requests that EPA take action in response to this Petition by February 1, 2017. In the absence of a grant of reconsideration and stay by that time, Entergy will consider the Petition to be denied, unless the parties have jointly agreed to a longer period of time for EPA to take action on the Petition.

II. DESCRIPTION OF PETITIONERS

EAI is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Arkansas. EAI provides electrical utility service to approximately 712,000 electric customers, deriving 81 percent of its operating revenues from electric customers in 2015. EAI owns portions of White Bluff and Independence and operates both plants. EAI is a regulated utility company subject to the rate and general operating jurisdiction of the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). All of the common stock of EAI is owned by Entergy Corporation.

EMI is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Mississippi, and is a co-owner of Independence. EMI provides electrical utility service to approximately 447,000 electric customers, deriving 89 percent of its operating revenues from electric customers in 2015. EMI is a regulated utility company subject to the rate and general operating jurisdiction of the Mississippi Public Service Commission and FERC. All of the common stock of EMI is owned by Entergy Corporation.

Entergy Power, LLC is an electric utility company that sells electric energy at wholesale and is a co-owner of Independence. Its principal business office is located in Little Rock, Arkansas. Entergy Power, LLC is an indirect wholly owned subsidiary of Entergy Corporation.

III. REQUEST FOR RECONSIDERATION

A. Reconsideration Is Required Under Clean Air Act Section 307(d)(7)(B).

EPA *must* grant reconsideration of a final action when a petitioner "can demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[7] In such a situation, reconsideration is mandatory, as the Clean Air Act ("CAA") commands that EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed."[8] EPA must grant this Petition because

[7] 42 U.S.C. § 7607(d)(7)(B).
[8] *Id.* (emphasis added).

(1) Entergy's objections are to actions EPA took in the Final FIP, or developments since the comment period closed, and thus could not have been raised during the comment period on the Proposed FIP; (2) the objections arose during the period for judicial review; and (3) the objections are of central relevance to the outcome of this rulemaking.

Reconsideration also is appropriate to correct clear errors, as the CAA provides for judicial invalidation of rules if errors are "so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made."[9] EPA should grant this Petition to address serious errors that are of central relevance to the Final FIP.

B. EPA Should Reassess its Imposition of Reasonable Progress Controls on Independence in Light of More Recent Air Quality Data and Corrected Contribution Data.

Data that became available after the close of the public comment period on the Proposed FIP confirm that reasonable progress controls on Independence for the first planning period are wholly unnecessary. Additionally, EPA's reasonable progress analysis relies on a false characterization of Independence's contribution to visibility impairment in Class I areas. EPA should reconsider the Final FIP and the controls on Independence in light of more recent air quality data, as well as corrected data regarding Independence's contribution to visibility impairment.

According to Interagency Monitoring of Protected Visual Environments ("IMPROVE") monitoring data for 2015, which became available subsequent to the close of the comment period, visibility continues to improve at a greater rate than the uniform rate of progress ("URP") in the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo").[10] In addition, the recent IMPROVE data further confirm that visibility in the two Arkansas Class I areas already is better than the RPGs that EPA finalized for the areas. EPA set the RPGs for the 20 percent worst days at 22.47 deciviews ("dv") for Caney Creek and at 22.51 dv for Upper Buffalo.[11] The recent IMPROVE data for both Class I areas demonstrate that monitored visibility impairment in the areas already is well below EPA's RPGs, as well as Arkansas' RPGs, and that visibility impairment is continuing to trend downward.[12] Given that Caney Creek and Upper Buffalo already have surpassed the URP goals, Arkansas' RPGs, and EPA's final RPGs for the first planning period, reasonable progress controls during the first planning period are not "*necessary*" to ensure reasonable progress towards the natural visibility goal.[13] There is simply no standard of reasonable progress that necessitates controls on

[9] 42 U.S.C. § 7607(d)(8).
[10] Assessment of Recent Class I Area IMPROVE Monitoring Data prepared by Trinity Consultants, Inc., at 3 (Aug. 8, 2016, updated Nov. 15, 2016) (hereinafter "Trinity Report") (attached as Exhibit A).
[11] 81 Fed. Reg. at 66,354.
[12] Trinity Report at 3. Actual visibility impairment at Caney Creek in 2015 was 20.41 dv, below Arkansas' RPG of 22.48 dv and EPA's final RPG of 22.47. Actual visibility impairment at Upper Buffalo in 2015 was 19.96 dv, below Arkansas' RPG of 22.52 and EPA's final RPG of 22.51. *Id.*
[13] *See* 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal").

Independence for this planning period, especially in light of the fact that the Regional Haze Program is designed to achieve its goals over a long horizon – by 2064.

EPA also should reconsider the need for NOx controls on Independence based on a corrected understanding of the plant's contribution to visibility impairment. In the Final FIP, EPA justified the need for NOx controls on Independence based on a false characterization of the plant's contribution to visibility impairment. EPA stated that, "Entergy's CAMx modeling shows that nitrate from Independence is responsible for 30 – 40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days."[14] This statement is false and must be corrected. EPA's statement indicates that on two of the 20 percent worst days, *30-40 percent of all impairment* at Arkansas' Class I areas is due to nitrates derived from NOx emissions from Independence. In reality, *30-40 percent of the impairment on these days that is due to nitrates* is attributable to Independence. But nitrates are a minute portion of visibility impairment at Arkansas' two Class I areas. The average total nitrate contribution from Independence to visibility impairment on these days is only 0.02 percent at Upper Buffalo and 0.03 percent at Caney Creek. Thus, the actual contribution is over three orders of magnitude less than EPA stated.

Entergy had no opportunity to comment on this mischaracterization of Independence's nitrate contribution to visibility impairment, which is of central relevance to the outcome of the rule. EPA should correct this mischaracterization and clearly acknowledge that the contribution of Independence to visibility impairment in Arkansas' Class I areas is almost meaningless.

In sum, EPA should reconsider the necessity of reasonable progress controls for Independence in light of the recent IMPROVE monitoring data as well as a corrected assessment of Independence's contribution to visibility impairment in Arkansas' Class I areas.

C. The SO_2 BART Determination in the Final FIP for White Bluff Failed to Consider Critical Information.

1. EPA materially misunderstood Entergy's comments regarding EPA's proposed SO_2 BART determination for White Bluff.

The Final FIP imposes SO_2 limits on White Bluff Units 1 and 2 premised on the installation of dry FGD, which EPA found to be cost-effective based on a 30-year amortization period.[15] EPA failed to consider Entergy's proposal to cease combusting coal in 2027 and 2028, which would limit the remaining useful coal-fired lives of the units and significantly alter the cost-effectiveness of SO_2 controls.[16] Entergy had no notice of or opportunity to timely comment

[14] 81 Fed. Reg. at 66,359.
[15] *Id.* at 66,335, 66,360.
[16] Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "EAI Comments") (attached as Exhibit B).

on EPA's failure, which was only evident in the Final FIP and EPA's associated Response to Comments.[17]

In the Final FIP, EPA unreasonably mischaracterized Entergy's White Bluff proposal, resulting in the Agency's failure to properly determine BART for White Bluff Units 1 and 2. EPA acknowledged that a binding requirement to cease combustion of coal at White Bluff would limit the remaining useful lives of Units 1 and 2 for the purpose of evaluating SO_2 controls, but mistakenly assumed that Entergy had not offered such a proposal. EPA explained, "If Entergy's alternative proposal had included accepting a binding requirement to burn only natural gas at White Bluff Units 1 and 2 after coal combustion ceases, or a binding requirement to completely shut down the units, *then we would agree that it would be appropriate to assume that SO_2 emissions from White Bluff will be zero beginning in 2027/2028*."[18] However, contrary to EPA's assertion, Entergy explicitly made such a commitment in its comments on the Proposed FIP:

> As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, *and is prepared to take an enforceable commitment to that effect*.[19]

EPA's conclusion that Entergy "does not propose…adopting a binding requirement to burn only natural gas or completely shut down the units"[20] is inexplicable in light of the plain language of Entergy's proposal. Because EPA determined that a binding requirement to cease burning coal would allow the Agency to assume that SO_2 emissions would be zero subsequent to the cessation of coal combustion, EPA must reconsider the SO_2 BART determination for White Bluff. Failure to do so is unreasonable and arbitrary and capricious.

EPA also asserted that Entergy's proposal to cease using coal at White Bluff appeared tied to EPA's acceptance of Entergy's separately proposed emission limits for Independence.[21] That assertion is incorrect. Nowhere in its comments did Entergy claim that its acceptance of a binding requirement to cease burning coal at White Bluff Units 1 and 2 was contingent on EPA's agreement to the emission limits that Entergy was proposing for Independence. Although Entergy proposed an approach addressing all four coal-fired units at White Bluff and Independence and provided modeling of its proposal demonstrating that its approach would achieve virtually the same visibility benefits as EPA's Proposed FIP for significantly less cost,[22] Entergy did not indicate that its proposed emission limits for Independence were a necessary element of its White Bluff proposal. In fact, in its comments, Entergy explicitly stated that the

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[17] 81 Fed. Reg. at 66,335, 66,360; Response to Comments for the Federal Register Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, at 52-54 (Aug. 31, 2016) (Docket ID No. EPA-R06-OAR-2015-0189-0187).
[18] 81 Fed. Reg. at 66,356-57 (emphasis added).
[19] EAI Comments at 5 (emphasis added).
[20] 81 Fed. Reg. at 66,356.
[21] *Id.* at 66,358 ("Entergy's comments provide no indication that it is willing to accept a binding requirement to cease coal combustion at White Bluff by 2027/2028, unless we also accept the elements of its alternative proposal that are applicable to Independence as satisfying the reasonable progress requirements.").
[22] EAI Comments at 45-46.

interim emissions reductions it offered, which included the emission limits for Independence, were a *complement* to its proposal for White Bluff.[23]

2. EPA did not account for Entergy's proposal regarding the remaining useful life of White Bluff in analyzing SO_2 controls.

Had EPA appropriately characterized Entergy's proposal for White Bluff, EPA would have used a shorter remaining useful life for White Bluff in its BART analysis. Proper accounting of remaining useful life is critical because, as EPA acknowledged in the Final FIP, "a shorter remaining useful life [at White Bluff Units 1 and 2] might result in a conclusion that dry scrubbers are not cost-effective…."[24] Indeed, as explained in Entergy's comments, Entergy's proposal for White Bluff rendered EPA's proposed BART determination inapplicable, requiring EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units.[25] Because EPA's FGD cost-effectiveness analysis failed to take into account Entergy's proposed binding commitment to cease combusting coal at White Bluff, a failure on which Entergy could not previously have provided comment, EPA must reconsider this issue. In doing so, EPA also should reconsider the cost-effectiveness of dry scrubbers in light of the correct control cost information, as explained in the following section.

3. Dry FGD is not cost-effective at White Bluff.

EPA calculates that installing and operating dry FGD at White Bluff would cost $2,565 per ton of SO_2 removed for Unit 1 and $2,421 per ton of SO_2 removed for Unit 2.[26] However, these cost estimates fail to account for Entergy's proposal, discussed above, regarding the remaining useful life of the units as well as data regarding the actual cost of controls. Had this information been properly considered, EPA should have estimated that the costs per ton of SO_2 removed would range from approximately $7,100 to $8,000 per ton of SO_2 removed, which is patently *not* cost-effective.[27]

EPA's cost estimate *failed to include over $495 million* that Entergy will be required to incur to install dry FGD on the White Bluff units.[28] EPA rejected certain costs in the analysis prepared for Entergy by Sargent & Lundy because Entergy did not provide to EPA the underlying 2009 and 2013 Alstom quotes on which Sargent & Lundy's cost analysis relied.[29] Because Entergy had no notice that EPA would require submission of these quotes, which contain non-public, highly confidential and proprietary information, to validate Entergy's cost analysis, Entergy is providing redacted versions of these quotes now.[30] The Alstom quotes

[23] *Id.* at 4 ("Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term.").
[24] 81 Fed. Reg. at 66,356.
[25] EAI Comments at 5.
[26] 81 Fed. Reg. at 66,386.
[27] Memorandum from Sargent & Lundy (Nov. 18, 2016) (hereinafter "Sargent & Lundy Memo") (attached as Exhibit C).
[28] *See* Sargent & Lundy Memo at 2.
[29] 81 Fed. Reg. at 66,383.
[30] 2009 Alstom Report (attached as Exhibit D) and 2013 Alstom Report (attached as Exhibit E). These reports contain confidential business information. Non-pertinent information has been redacted.

demonstrate that EPA improperly excluded extensive costs associated with "Balance of Plant" items, which are items not included in the FGD supplier's scope, but which are necessary to integrate the FGD system into the plant.[31] The quotes also demonstrate that EPA underestimated escalation by using the Chemical Engineering Plant Cost Indices ("CEPCI") instead of relying on more accurate information from the vendor.

The more detailed and accurate cost analysis prepared by Sargent & Lundy, which includes costs improperly excluded by EPA and correctly predicts tons removed, estimates that dry FGD cost-effectiveness will range from approximately $7,100 to $8,000 per ton if the units cease combusting coal in 2027-2028.[32] Even if certain costs rejected by EPA were excluded in Sargent & Lundy's cost estimate (i.e., allowance for funds used during construction ("AFUDC"), escalation, and owner's costs), the cost-effectiveness of dry FGD at White Bluff would range from approximately $5,400 to $6,100 per ton.[33] Regardless of which estimate is used, these costs exceed those that EPA has previously rejected in other BART analyses and thus are too high to represent BART for the White Bluff units.[34] As a result, dry FGD cannot constitute SO_2 BART for White Bluff Units 1 and 2. Accordingly, EPA should reconsider the White Bluff SO_2 BART.

4. EPA must reconsider SO_2 BART for White Bluff even in the absence of a DSI analysis.

In the Final FIP, EPA argues, for the first time, that it would be necessary to assess dry sorbent injection ("DSI") as an interim control if the White Bluff units cease to combust coal, and indicates that this lack of DSI analysis somehow negates EPA's obligation to conduct a reasonable BART analysis of dry FGD at the White Bluff units. Entergy did not have notice of or an opportunity to comment on this assertion, which is of central relevance to the Final FIP. The lack of a DSI analysis, which EPA had not previously requested, does not absolve EPA of its obligation to properly assess the cost-effectiveness of dry FGD.

EPA explains in the Final FIP that "[b]ecause Entergy has provided no analysis to demonstrate that there is no more effective interim SO_2 control that would constitute BART, the company's proposed strategy is not adequate to ensure that the BART requirements for White Bluff Units 1 and 2 will be met."[35] EPA ties the lack of a DSI analysis to its determination that it

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[31] Upon further review, Sargent & Lundy determined that costs associated with ductwork downstream of the booster fans were included in the Alstom quote. The updated cost estimates in this Petition remove these costs. Sargent & Lundy Memo at 2.

[32] *Id.* at 3.

[33] *Id.*

[34] EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,090/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,317, 9,331-33 (Feb. 18, 2014); Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. 58,570, 58,630 (Sept. 21, 2011); Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012).

[35] 81 Fed. Reg. at 66,356.

need not even consider Entergy's finding that FGD is not cost-effective in light of its proposal for White Bluff. This is a false premise; the appropriateness of DSI as an interim control measure is irrelevant to the assessment of whether dry FGD is cost-effective. As outlined above, EPA failed to account for the proposed remaining useful life of Units 1 and 2 when assessing dry FGD as a control technology, as well as certain costs associated with such controls, and must do so now on reconsideration. To the extent that EPA *also* believes that an assessment of DSI as a potential control technology is warranted, such assessment is wholly independent of the FGD assessment.

Despite the fact that EPA's request for a DSI analysis arose for the first time in the Final FIP, Entergy is willing to develop and provide the analysis if EPA grants reconsideration on SO_2 BART for White Bluff. Additionally, Entergy understands that the Arkansas Department of Environmental Quality ("ADEQ") will develop a state implementation plan ("SIP") to replace portions of the Final FIP, including the BART controls for White Bluff, and Entergy will submit a DSI analysis to ADEQ, if required, as part of the SIP development process.

D. EPA's LNB/SOFA Assumptions Are Unsupported and Unreasonable, and Must Be Revised.

EPA should reconsider whether NOx controls should be required for either White Bluff or Independence. As addressed in Section III.A above, NOx controls on Independence to address reasonable progress are unnecessary for this first planning period. Further, EPA should reconsider its imposition of source-specific NOx BART controls in the Final FIP and instead determine that compliance with CSAPR is acceptable for compliance with the NOx BART requirements in Arkansas, including for White Bluff, as addressed more fully in ADEQ's Petition for Reconsideration and Request for Administrative Stay.[36]

However, if EPA denies reconsideration on these threshold issues, EPA must grant reconsideration on the compliance deadline and NOx emission limits applicable to both White Bluff and Independence. The compliance deadline and NOx limits are not logical outgrowths of the Proposed FIP, are not reasonable and fraught with errors, and are of central relevance to EPA's determination of NOx BART in the rulemaking.

1. EPA must extend the 18-month timeline for the installation of LNB/SOFA to Three Years.

a. The 18-month deadline is not a logical outgrowth of the proposed rule and was promulgated in error.

The Final FIP unlawfully shortens the compliance deadline for the NOx emission limits for White Bluff and Independence from three years to 18 months.[37] EPA proposed a three-year NOx compliance deadline for these plants and did not indicate in the Proposed FIP that it was considering a shorter deadline. The 18-month deadline is not a logical outgrowth of the proposed compliance deadline. While Entergy stated in its comments that it was prepared to

[36] ADEQ Petition at 5-8.
[37] 81 Fed. Reg. at 66,338, 66,354.

meet the proposed three-year deadline,[38] it lacked notice and had no opportunity to comment on its ability to comply with a shortened compliance deadline.

EPA erred in relying on comments from environmental organizations when contracting the compliance timeline.[39] First, the environmental organizations requested a shorter compliance deadline only for White Bluff, not for Independence.[40] Indeed, while the organizations asserted that LNB/SOFA could be installed on Independence in under a year, the comment concluded that "three years is more than reasonable."[41] Even if the environmental organizations had requested a shortened compliance deadline for both plants, it is well-established that EPA "cannot bootstrap notice from a comment." *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983); *Am. Fed'n of Labor v. Donovan*, 757 F.2d 330, 340 (D.C. Cir. 1985).

Further, the environmental organizations' comments on installation of LNB/SOFA fail to provide a reasonable justification for the shorter compliance timeline. The comments were based on an expert report, which, in turn, relied on a 10-year-old vendor association report that did not consider permitting considerations, a company's internal project development and approval process, site-specific factors, or reliability concerns.[42] The vendor association report explicitly recognized that "[v]ariations in the schedule may occur due to site specific conditions that may increase or decrease the typical deployment time."[43] The vendor report also does not appear to allow sufficient time for testing and optimization of equipment, providing only one week for commissioning and startup.[44] Because the environmental organization comments relied on outdated, generic information about timing, they do not provide a proper basis for the shortened deadline for these specific units. Notably, EPA has not even attempted to provide any explanation of how this shorter deadline is reasonable for White Bluff and Independence in light of site-specific and company-specific considerations. Nor does EPA appear to have required such a short timeframe for the installation of controls in other regional haze plans. Even for AEP's Flint Creek plant, where SO_2 control equipment *is installed and functioning already*, EPA granted the company 18 months to make any modifications necessary to ensure the controls can meet the BART limit.[45]

b. The 18-month deadline is unreasonable.

The 18-month deadline to install LNB/SOFA at White Bluff and Independence is infeasible, as it does not guarantee sufficient time to develop, plan, permit, install, tune, and test the equipment. Specifically, a project of this scope requires Entergy to develop a prevention of significant deterioration ("PSD") permit application, obtain a PSD permit, comply with the

[38] EAI Comments at 13-14.
[39] 81 Fed. Reg. at 66,378.
[40] Comments of Earthjustice, National Parks Conservation Association, and Sierra Club at 25 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "Sierra Club Comments").
[41] *Id.* at 39.
[42] *Id.* at 25; Technical Support Document to Comments of Conservation Organizations, Prepared by Victoria R. Stamper, at 46 (Aug. 5, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0171) (hereinafter "Stamper Report").
[43] Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, Institute of Clean Air Companies, at 4 (Dec. 4, 2006), available at https://c.ymcdn.com/sites/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[44] *Id.*
[45] 81 Fed. Reg. at 66,338.

company's internal planning and prudence review procedures, complete a request for proposal ("RFP") process, select a vendor, procure equipment, schedule outages, install equipment, and then tune and test the equipment. Completion of all of these steps will require more than 18 months, even though Entergy already has obtained the necessary PSD permit for White Bluff, and is in the process of developing the PSD permit application for Independence.[46] Entergy would only be able to complete installation and tuning of LNB/SOFA on all four units by the final deadline if it circumvented its internal planning and prudence review procedures and completed the tuning and testing process *after* the compliance deadline.

The internal process that must be completed before the performance of any equipment work is robust, with preparation for this work just getting underway with respect to Independence. First, projects over $20 million, like the installation of LNB/SOFA, are subject to an internal company approval process that includes risk review and investment procedures. This process takes approximately two months and requires approval from several levels of Entergy management. Once the review process has been completed, Entergy can undertake project-specific planning. An engineer will draft project specifications based on the Final FIP requirements and design characteristics, a process that takes approximately two months. These specifications will be included in an RFP, which will be put out for a four- to six-week bidding process. Once a vendor is selected, negotiation of the final contract will take an additional four to six weeks.

Simultaneous to this internal process, Entergy must prepare a PSD permit application for the installation of LNB/SOFA at Independence.[47] Despite the fact that work already is proceeding, the earliest the application will be ready for submittal to ADEQ will be mid-December. ADEQ approval is expected to take, at a minimum, between six and eight months, resulting in permit issuance between mid-June and mid-August 2017, but this process could take longer for a variety of reasons outside of Entergy's control. For example, the permitting process could be extended if significant public comments are received on the draft permit that must be addressed by the ADEQ before a final permit can be issued, due to agency resource constraints, or due to an appeal of the final permit to the Arkansas Pollution Control and Ecology Commission, which, absent additional regulatory proceedings, would result in an automatic stay of the permit pending final resolution of the appeal.

Once the permit is issued and the final contract has been signed, the selected vendor must design and fabricate the equipment, which takes approximately eight months. Outages must be scheduled for all four units, each lasting between six and seven weeks. Once installation is complete, each unit will need to undergo four weeks of boiler tuning and two weeks of performance verification testing to demonstrate that the controls are achieving the anticipated NOx reductions. After this, Entergy will have to perform a final phase of fine-tuning and training. During the final phase, which lasts approximately five months, each unit will undergo a three-month procedure review during which the system description is re-written to include the new equipment and components, and the operating procedures are updated. This process cannot

[46] Although Entergy already has acquired control equipment for one unit at White Bluff, equipment still must be obtained for the second White Bluff unit and both Independence units to comply with the requirements in the Final FIP.

[47] As noted above, Entergy already has obtained a permit to install LNB/SOFA on White Bluff but does not yet have all the equipment needed to do so.

be truncated as it requires the operators to observe performance during all operating scenarios, including startup, shutdown, and periods of load transition. The staff must then be trained on both the system description and the operating procedures, which typically takes a month. An additional month is needed to validate operating configurations to determine which combinations result in the best load profile. It would be imprudent not to complete the entire training and fine-tuning process prior to the compliance deadline.

Even with a truncated schedule, Entergy cannot reasonably expect to meet the 18-month deadline. At best, Entergy could take the following steps, which increase risk and cost without any guarantee of compliance. It could circumvent its normal internal procedures, including its risk and prudence reviews and its process for obtaining competitive bids from multiple vendors. Entergy would be required to perform a more limited risk and prudence review, would have to forgo a complete bidding process in favor of using a pre-selected vendor that can fabricate and install the equipment as quickly as possible, and may even need to engage this vendor prior to having all regulatory approvals in hand. These internal procedures are in place to attempt to ensure cost recovery, and failure to comply with them puts the company at risk of making investments that the APSC later determines are not in the public interest and therefore not eligible for cost recovery. The schedule also does not allow for any delays associated with the PSD permitting process.

Finally, even with these truncated procedures, and assuming final PSD permit issuance in mid-June to mid-August 2017, the timeframe allowed in the Final FIP is insufficient for Entergy to conduct thorough testing and tuning of the NOx control equipment, where unforeseen issues frequently arise and must be addressed to ensure compliance. For example, it is common during the installation process to discover previously unknown equipment issues that complicate installation or hinder the expected performance of the installed equipment. Installation of controls involves many variables and each unit has unique characteristics, resulting in unpredictable challenges. As an example, small, unforeseen differences in mill performance or coal pulverization could result in problems that must be addressed to ensure the LNB/SOFA equipment performs as expected.

In light of these site-specific considerations, including the mandatory regulatory approval process, EPA should grant reconsideration and revise the 18-month deadline to provide the full three years provided in the Proposed FIP for installation of LNB/SOFA at White Bluff and Independence. This will allow time for Entergy to comply with its internal planning and prudence review procedures, to obtain all required approvals, and ensure that the controls are properly tuned prior to the compliance deadline. At a minimum, EPA should grant reconsideration and provide at least 30 months for the installation of LNB/SOFA at White Bluff and Independence as this is the minimum amount of time Entergy anticipates that the NOx compliance deadline could be met even by truncating its internal procedures and barring any unforeseen issues.

2. EPA must revise the NOx limit and averaging period that apply during periods of low load.

In the Final FIP, EPA unlawfully introduced, for the first time, a NOx emission limit of 671 lb/hr on a rolling 3-hour average that applies when the White Bluff and Independence units are operating at less than 50 percent of their maximum heat input capacity.[48] In contrast, EPA had proposed an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average that would apply regardless of the capacity at which the units were operating.[49] Entergy did not have notice of or an opportunity to comment on the significant change in the Final FIP to the limit and averaging period that apply when the units are operating at low loads. Entergy explained in its comments on the Proposed FIP that a higher limit is necessary during periods of low load operation because the LNB/SOFA system is designed to operate primarily in the range of 50-100 percent of unit load, and the vendor would not guarantee that LNB/SOFA could meet a limit of 0.15 lb/MMBtu for operating loads below 50 percent.[50] While Entergy appreciates EPA's apparent attempt to account for periods of low load in the Final FIP, EPA must reconsider the emission rate and averaging period that apply when the units are operating at less than 50 percent of the maximum heat input capacity.

First, Entergy did not have an opportunity to comment on the new emission limit and averaging period that apply during low load operation. EPA has not explained why either the limit that it established or the shorter averaging period are appropriate for either White Bluff or Independence, given that they were not raised or considered in the Proposed FIP or in Entergy's comments. The final limit and averaging period are not logical outgrowths of the Proposed FIP and they are plainly unlawful, arbitrary and capricious. EPA must grant reconsideration of these elements of the Final FIP.

Second, the new averaging period is unworkable for low load operation and will result in exceedances of the limit. During periods of load transition and, in particular, periods of reduced load, NOx is very sensitive to changing conditions such as air flow, fuel flow, and burner tilt position. When load is being ramped up or down, and mills are put in or out of service, NOx can spike to levels well above typical levels for short periods of time. Within minutes of the excursion, NOx typically will return to and stabilize at the steady state level. With the short 3-hour averaging period, a single 15-minute spike in NOx could result in NOx exceeding the low-load NOx emission limit for a 3-hour period, even if the remaining 165 minutes were below compliance levels.[51] A 30-boiler-operating-day period is necessary to moderate the variations in NOx due to load transition and low load.

Finally, the low-load NOx emission limit, which EPA set at one half the limit proposed by Entergy, also is problematic. It offers no compliance margin, which is necessary to account for increased NOx levels that occur as a function of low load operation, and the unavailability of SOFA when the unit is operated at less than 30 percent of capacity. When load falls below 50 percent, NOx levels increase as a percentage of heat input, trending upwards as load is reduced. This phenomenon is due to the increased levels of excess air that are used to ensure safe boiler

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[48] 81 Fed. Reg. at 66,344, 66,354.
[49] 80 Fed. Reg. at 18,974, 18,997.
[50] EAI Comments at 50.
[51] *See* Memorandum from Foster Wheeler (hereinafter "Foster Wheeler Memo") (attached as Exhibit F).

operation during low loads. During load swings, control systems lead load increases with increases in air flow and follow load decreases with reductions in air flow. This excess air leads to NOx formation from nitrogen-laden air. Not only are NOx emissions generated at a higher rate at low load, but NOx control options are limited during these periods. SOFA is unavailable when the boiler operates below 30 percent capacity, including during startup, because there is insufficient air to support both good combustion and maintain overfire air flow to the boiler. As a result, the SOFA system cannot provide any NOx reduction during these operational periods.

Accordingly, EPA should reconsider the NOx limit and averaging time that applies to periods of low load operation and adopt the limit requested by Entergy in its comments: a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence.[52] At the least, EPA should revise the NOx averaging time to a 30-boiler-operating day period, and the limit to 895 lb/hr.[53] This will allow the inevitable NOx variations to be smoothed out over the averaging period, resulting in a limit that is possible to achieve.

IV. REQUEST FOR STAY

A. EPA Should Grant a Stay Pursuant to the CAA and the APA.

Section 307(d)(7)(B) of the CAA authorizes EPA to stay the effectiveness of a rule for up to three months during reconsideration,[54] which can be extended for additional three-month periods. Additionally, the Administrative Procedure Act ("APA") authorizes EPA to stay the effectiveness of a rule indefinitely. Under the APA, "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review."[55] EPA has applied this standard to CAA actions.[56]

Unlike a judicial stay, an administrative stay does not require a demonstration of irreparable harm. The APA states:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court . . . may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.[57]

The APA deliberately contrasts what is required for an administrative stay—"justice so requires"—and a judicial stay—"conditions as may be required" and "irreparable harm." Similarly, CAA Section 307(d)(7)(B) authorizes an administrative stay, but does not premise that

[52] EAI Comments at 49.
[53] Foster Wheeler Memo at 4.
[54] *See* 42 U.S.C. § 7607(d)(7)(B).
[55] 5 U.S.C. § 705.
[56] *See, e.g.,* Prevention of Significant Deterioration ("PSD") and Nonattainment New Source Review ("NSR"): Aggregation, 75 Fed. Reg. 27,643 (May 18, 2010).
[57] 5 U.S.C. § 705. EPA has stayed a rule pursuant to Section 705 even after the rule's effective date has passed. *See Stay of Federal Water Quality Criteria for Metals*, 60 Fed. Reg. 22,228 (May 4, 1995).

stay on a finding of irreparable injury, noting simply that "[t]he effectiveness of the rule may be stayed during such reconsideration…for a period not to exceed three months."[58]

EPA should administratively stay the Final FIP's emission limitations for White Bluff and Independence while it addresses the issues identified above in Entergy's Petition, and while the Eighth Circuit considers Entergy's petition for review of the Final FIP. Specifically, Entergy requests that EPA stay 40 C.F.R. §§ 52.173(c)(6)-(8) with respect to White Bluff and §§ 52.173(c)(24)-(26) with respect to Independence. As explained below, a delay in implementation of the FIP would prevent harms to Entergy, with negligible visibility impact, while the Final FIP is reviewed. An administrative stay also would allow ADEQ time to develop its replacement SIP.

B. Justice Requires that EPA Grant a Stay.

1. Compliance with the SO_2 limits would immediately and irreparably harm Entergy, its co-owners, employees, customers, and communities.

To meet the Final FIP's SO_2 emission limits at White Bluff and Independence, Entergy must make plans for compliance now. Implementation of the Final FIP requires Entergy to make a Hobson's choice as soon as possible to either (1) permit, design, gain regulatory approval for, construct, install, and tune dry scrubbers on all four units by October 27, 2021, or (2) deactivate the units by that date, eliminate 230 Entergy jobs in rural Arkansas,[59] dramatically reduce the local tax revenues, and commit to new resources to replace a significant portion of its generating capacity. Either path for compliance with the SO_2 emission limits at White Bluff and Independence is a complex undertaking that must be pursued independently for each unit, and will result in immediate and irreparable harm to Entergy, its co-owners,[60] and local economies.

To ensure compliance, either path would require Entergy to begin making commitments and significant financial investments in the immediate future and without state agency review of the proposed path. Entergy must pursue both potential paths for as long as there is regulatory uncertainty.[61] Entergy would suffer irreparable harm if it is forced to proceed before EPA acts

[58] 42 U.S.C. § 7607(d)(7)(B).

[59] Entergy also directly employs several hundred contractors over the course of the year, for both seasonal outage work and ongoing plant support.

[60] As described in petitions for reconsideration of the Final FIP filed by co-owners of the White Bluff and Independence plants, the harms to these co-owners would be significant. For example, deactivation of both plants in October of 2021 would create the immediate need to add an estimated 500 megawatts ("MW") of firm generation capacity to the Midcontinent Independent System Operator ("MISO") side of the Arkansas Electric Cooperative Corporation ("AECC") system. This replacement capacity is estimated to require the investment of $490,000,000. The levelized investment recovery cost of this generation capacity to AECC's member cooperatives would be approximately $34,000,000 annually. Jonesboro City Water and Light estimates that replacement of its share of ownership of the generation capacity of the White Bluff and Independence units in 2021 would result in increased costs between $16.3 million and $25 million, *in 2021 alone*, which translates to a 17-27 percent increase in customer rates. *See* Petition for Reconsideration and Request for Administrative Stay of AECC and Petition for Reconsideration and Request for Administrative Stay of Energy & Environmental Alliance of Arkansas ("EEAA").

[61] Either choice would cause irreparable harm in so far as significant financial investments would need to be made that could not be reversed if the Final FIP were later revised or vacated. Additionally, due to the lead time needed to install FGD technology or to prepare for permanent retirement, more time is needed to select one of these two options than the Final FIP allows. As described in this section, regulatory reviews are required for both paths, so the

on the Petition and before the Eighth Circuit determines the merits of Entergy's petition for review of the Final FIP. And yet, to meet the compliance deadline, it will be compelled to do so or risk noncompliance with the Final FIP. The first path, installing dry scrubbers on all four units, would be a massive undertaking costing approximately $2 billion. The first phase of this multi-phase project would have to begin as soon as the decision to proceed was made, as the process would require the entirety of the five years allotted in the Final FIP, as explained in further detail below, including spending over $150 million in the first 18 months alone. The second path, deactivating the units, is complicated and costly in different ways, as explained below. Both paths cause Entergy irreparable harm.

Given the lead times for either path, Entergy must start immediately to conduct analyses and reviews to support its internal decision-making process, which will take several months. Entergy's internal review process would assess both approaches, particularly analyzing and comparing the economics of each approach, and would be coordinated with the co-owners of White Bluff and Independence. Assessing the costs of the two approaches is extremely complicated. For example, for EAI to retire an existing generating unit, EAI must provide at least six months' notice to MISO, the regional transmission operator that dispatches White Bluff and Independence, of its intent to retire the unit. Because of the interconnected nature of the electric grid, a decision to retire a unit can have implications for the remainder of the grid, some of which may require upgrades to the transmission system to ensure that the grid can be operated reliably after the generating unit is retired. Accordingly, owners/operators of a generating unit typically would request that MISO perform an "Attachment Y-2 study," which would determine, on a non-binding basis, whether the retirement of the generating unit (i.e., White Bluff or Independence) would impact transmission system reliability, or whether the plant would need to continue to operate until transmission upgrades or other system changes to maintain reliability can be completed. In Entergy's experience, an Attachment Y-2 study takes approximately three to four months for a standard request. However, this situation is far from standard; assessing the retirement of four units totaling nearly 3400 MW of capacity may take much longer. Entergy would incorporate the Attachment Y-2 results into its internal economic analysis. Depending on the time needed to perform the economic analysis, coordinate with co-owners, and obtain the results of MISO's Attachment Y-2 study, this decision-making process would take between six and nine months.

Compliance with the FIP also requires EAI, the operator of all four units, along with the other co-owners of White Bluff and Independence to adhere to other regulatory processes, each unique to each co-owner.[62] In similar cases involving significant capital investments at existing generating units, EAI has sought a declaratory order from the APSC confirming that the selected path is in the public interest.[63] Because EAI is a rate-regulated entity, costs prudently incurred in the provision of electrical service typically are recoverable from customers, but cost recovery can occur only after the costs are reviewed by the APSC and a regulatory rate adjustment is made. In

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compressed timeline mandated by the Final FIP requires Entergy to simultaneously prepare for both paths in the event that the selected path does not earn regulatory approval.

[62] For example, EMI also has regulatory reviews and approvals before the Mississippi Public Service Commission that it must pursue. *See also* Petition for Reconsideration and Request for Stay of Energy and Environmental Alliance of Arkansas.

[63] *See. e.g.,* APSC Docket No. 09-024-U (Seeking public interest finding for installation of environmental controls at White Bluff Units 1 and 2).

other words, a public interest finding addresses the prudence of the investment; it does not address the prudence of the management of the incurrence of the costs nor does it modify base rates or effect other charges to include those costs (which would be the result of a separate review by the APSC in a later proceeding). If cost recovery is not approved or if recovery is significantly delayed, EAI could be deprived of a reasonable opportunity to receive adequate recovery of costs incurred.[64] In either case, the preparation of the application and supporting testimony could take up to six months. Additionally, completion of discovery, an APSC-determined procedural schedule with multiple rounds of testimony from the APSC General Staff, Attorney General, and other intervenors, a public hearing, and the issuance of a final order, could take an additional 14 months to complete. Accordingly, the state regulatory process may take as long as 20 months, and that is prior to any potential challenge by EAI to the APSC's final order, which could include a petition for rehearing and subsequent appeal.

Should Entergy choose to install dry scrubbers on all four units, Entergy would be forced to make considerable expenditures within the next few years, effectively prohibiting any alternative approach. Of the approximately $2 billion that Entergy estimates it would spend for scrubbers on White Bluff and Independence, Entergy would need to spend well in excess of $38 million within the first year, $150 million within 18 months, and $305 million within 24 months.[65]

The work to install the dry scrubbers also would need to begin immediately to comply with the FIP's five-year deadline. During the preliminary engineering phase of the project, which is expected to take between six and 12 months, an engineer would need to develop detailed specification requirements for the engineering, procurement, and construction of the FGD systems. Contractors would need at least three months to develop proposals, and then several weeks would be required to evaluate the proposals and award the contract. Because White Bluff and Independence have different co-owners, two separate FGD contracts would need to be developed. Afterward, the FGD contractor at each plant would proceed with the detailed engineering phase, during which every component required for a complete and operable FGD system would be designed and fabricated. Next, the engineered components would be delivered to the sites and the FGD contractor at each site would erect them and integrate them into the existing plants. A tie-in outage must be taken for each unit so that physical connections to existing systems can be made. Because Entergy would not take simultaneous outages at all four units for reliability reasons, and because there would be two FGD contracts awarded at different times, the construction phase likely would be staggered by approximately one year across all four units. Once constructed, equipment startup and commissioning would occur, followed by operational tuning and performance optimization. Performance testing would then

[64] EAI has elected to be regulated pursuant to Ark. Code Ann. § 23-4-1201 et seq., which provides that a public utility may choose to be regulated under a formula rate review mechanism that provides for an annual streamlined review of a public utility's rates and designation of a test period based on a projected test year. EAI's APSC-approved Rate Schedule No. 44, Formula Rate Plan Rider ("Rider FRP") provides for annual adjustment of customers' rates based on a comparison of EAI's earned return on common equity and its target return rate approved by the APSC. However, pursuant to Ark. Code Ann. § 23-4-1207 and Rider FRP, the annual Rider FRP revenue increase or decrease for each rate class shall not exceed four percent of each rate class' revenue. Accordingly, in complying with the FIP, EAI may pursue cost recovery for those costs pursuant to Rider FRP or other potential cost recovery mechanisms.

[65] These estimates were developed by Sargent & Lundy but do not include the significant costs for AFUDC, escalation and owner's costs that Entergy also will incur. Sargent & Lundy Memo at 5.

be conducted to confirm compliance with emission limits. The FGD contractor would need approximately three years to complete engineering and construction of one unit, followed by up to six months of commissioning, startup, performance optimization, and performance testing.

Alternatively, were Entergy to choose deactivation, the company would have to secure additional regulatory approvals as quickly as possible to provide for a smooth transition to replacement power by the 2021 deadline. The company must provide six months' notice to MISO before a generator can be retired (the "Attachment Y" process described above). .

Entergy next would need to procure and build replacement power because White Bluff and Independence currently are needed for Entergy to provide reliable electricity generation to its customers and meet its obligations to MISO. Entergy's resource planning process would consist of designing, gaining regulatory approval for, constructing, and making operational a new alternative generating unit. Entergy anticipates that the replacement generation would be a combined cycle gas turbine ("CCGT"),[66] which may require construction of a new gas pipeline to the selected site. Depending on the site that is selected for the CCGT, rights-of-way may need to be obtained. Transmission would need to be planned and built to connect the new CCGT with the grid. To construct replacement generation as quickly as possible, Entergy must prepare an environmental permit application, prepare RFPs for the construction, select a vendor, and submit a permit application. The time required for this process means that replacement power would not be available for five years at the earliest, thus exposing customers to market capacity prices in the interim. Accordingly, planning must begin immediately to limit, as much as possible, the duration of customer exposure to market prices. In the meantime, even maintaining reliability through the purchase of power would require Entergy to accelerate planned transmission projects. A project that currently is planned to be completed in 2024 would have to be accelerated to be completed in 2020, at an additional cost of $8 million and with a start date in 2017.

Ceasing operations at White Bluff and/or Independence would cause irreparable harm to Entergy employees and the communities in which they work. The total number of jobs created and supported by the White Bluff plant alone is estimated to be 1,237.[67] Entergy itself employs 105 full-time employees at White Bluff, along with 10 Entergy Service Company employees that support White Bluff full time. White Bluff also employs approximately 300 contractors for at least six weeks in the spring and fall each year for planned outage support. Additionally, there are about 20 contractors that work full time in security, coal dust management, janitorial, lawn maintenance, ash management and scaffolding support. At Independence, Entergy employs 108

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[66] White Bluff cannot be replaced by renewable energy. White Bluff provides approximately 1,600 MW of reliable capacity to the MISO system and there are no practical or reasonable renewable generation options to meet the MISO resource adequacy requirements currently satisfied by White Bluff. Replacement of White Bluff would require 3,200 MW of solar power (necessitating 22,000 acres of panels), or 10,000 MW of wind generation (necessitating 7,000 windmills that would have to be located in the plains states hundreds of miles away from Entergy's load). Additionally, there is insufficient biomass fuel available to supply a 1,600 MW replacement biomass plant, and even if sufficient fuel were available, it would take an impracticable amount of trucks to deliver the necessary fuel. None of these options is feasible.

[67] Willie Lee Brooks, Jr., Senior Analyst, Economic & Financial Risk, *What is the Economic Impact of the White Bluff Electric Power Plant?*, at 2, Arkansas Electric Cooperative Corporation (May 30, 2014), available at http://www.arkleg.state.ar.us/assembly/2015/Meeting%20Attachments/890/I12666/HANDOUT%202%20-%20HIGHLEY%20%20Economic%20Impact%20of%20White%20Bluff%20Electric%20Pwr%20Plant.pdf

full-time employees, along with seven Entergy Service Company employees that support Independence full time. Independence also employs 83 contractors, who provide janitorial services, maintenance support, ash disposal services, and work on insulation and scaffolding during outages. If White Bluff and Independence were to cease operations, the company would have to lay off or reassign its employees, and the contractors would be out of work. These shutdowns would have significant impacts on the rural Arkansas communities where the plants are located. For example, the estimated the value of White Bluff to the local economy is $173 million.[68]

2. Compliance with the NOx limits would immediately and irreparably harm Entergy, its co-owners, employees, customers, and communities.

As explained above in Section III.D, the 18-month deadline to install LNB/SOFA at White Bluff and Independence is infeasible, as it does not provide sufficient time to develop, plan, permit, install, and appropriately tune the equipment. Entergy could complete installation of LNB/SOFA at all four units by the final deadline only by circumventing its normal internal procedures and the tuning and training process. Entergy would be forced to perform a more limited risk and prudence review, would have to forgo a competitive bidding process in favor of using a pre-selected vendor for fabrication and installation, and may even need to engage this vendor prior to having all regulatory approvals in hand. These procedures are in place to attempt to ensure cost recovery, and failure to comply with them puts the company at risk of making investments that the APSC later determines are not in the public interest and therefore ineligible for cost recovery. Additionally, Entergy would be forced to comply with the emission limits prior to the conclusion of its tuning and training procedures. Even with these truncated procedures, the schedule does not allow for any unforeseen issues in the installation and tuning process, which frequently arise and complicate installation or hinder the expected performance of the installed equipment.

Implementation of the Final FIP forces Entergy to choose between two untenable options each resulting in irreparable harm and unnecessary risk: (1) increasing costs and risk through rushed work and non-compliance with company prudence procedures, with no guarantee of FIP compliance once the work is completed, and (2) taking more time than the Final FIP permits, resulting in cessation of operation of the White Bluff and Independence units until LNB/SOFA can be installed. Beyond the fact that cessation of operations would necessitate Entergy to obtain costly replacement power on the open market, critically, it also could cause reliability issues, as generation from White Bluff and Independence is necessary for Entergy to provide reliable electricity generation to its customers and meet its obligations to MISO. In light of this, EPA must issue a stay of the deadline for compliance with the NOx limits until a more appropriate deadline can be set.

[68] *Id.*

3. A stay would prevent harm to Entergy and its co-owners, customers, and communities but would still allow Arkansas to meet its regional haze goals.

Arkansas already is below the URP and EPA's RPGs, and thus a delay in the implementation of the FIP would not contribute to unacceptable visibility impairment. As discussed previously, the IMPROVE data for January 2014 through December 2015 show that visibility continues to improve at a greater rate than the URP in Caney Creek and Upper Buffalo.[69] The recent IMPROVE data also confirm that visibility in the two Arkansas Class I areas already is better than EPA's final RPGs for the areas.[70] Accordingly, a stay would not interfere with attainment of the URP or the RPGs.

D. Entergy Also Meets the Four Factors that Courts Consider When Assessing Judicial Stay Requests.

Although the judicial test for analyzing a request for a stay does not apply here, Entergy's request for stay nonetheless satisfies this test. First, as described above, Entergy has made a strong showing of likelihood of success on the merits. For the reasons explained in this Petition, the Final FIP contains significant errors and unreasonable requirements upon which Entergy was unable to comment during the period for public review, and that are not logical outgrowths of the Proposed FIP. The CAA *requires* that EPA reconsider these elements of the Final FIP. Second, Entergy would be irreparably harmed if the Final FIP is not stayed. As explained above, implementation of the FIP would force Entergy to make expensive choices about the installation of controls and possible deactivation of units in very short order. Entergy would be forced to spend significant amounts of money once these choices are made. Third, a stay of the rule would not cause harm. Visibility in Arkansas' Class I areas already is improving at a rate greater than the URP for each area, and the areas already have surpassed EPA's final RPGs for the first planning period. Implementation of SO_2 and NOx controls at White Bluff and Independence is not needed to achieve either the URP or the RPGs. Fourth, the balance of harms and the public interest favor a stay. A stay would prevent significant, irreparable harm to Entergy with little visibility impact, as Arkansas already has met the goals that the installation of FGD and LNB/SOFA are designed to achieve. It also would prevent the harm to employees and local communities that would ensue from the deactivation of any of the units. In light of this, a stay is appropriate and just, and should be granted.

V. CONCLUSION

For the reasons discussed above, Entergy urges EPA, by February 1, 2017, to reconsider and stay certain provisions of the Final FIP to avoid the harms to Entergy, its employees, co-owners, customers and local communities, as described herein.

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[69] Trinity Report at 3.

[70] See *supra* at 4.

Dated: November 23, 2016

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List of Exhibits

Exhibit A: Assessment of Recent Class I Area IMPROVE Monitoring Data prepared by Trinity Consultants, Inc., at 3 (Aug. 8, 2016, updated Nov. 15, 2016)

Exhibit B: Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153)

Exhibit C: Memorandum from Sargent & Lundy (Nov. 18, 2016)

Exhibit D: 2009 Alstom Report

Exhibit E: 2013 Alstom Report

Exhibit F: Memorandum from Foster Wheeler

Exhibit A

ASSESSMENT OF RECENT CLASS I AREA IMPROVE MONITORING DATA

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Trinity Project No. 163701.0059

August 8, 2016

Updated November 15, 2016

Assessment of Recent Class I Area IMPROVE Monitoring Data

Since the August 7, 2015 submittal of Trinity Consultants' *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant* (Trinity's report), the complete set of 2015 measured concentration data from the Interagency Monitoring of Protected Visual Environments ("IMPROVE") network of Class I area monitors has become available. It is prudent to review this data for the two Arkansas Class I areas – Caney Creek ("CACR") and Upper Buffalo ("UPBU") – to determine if the trends identified in Trinity's report continue.

A summary of all available haze index values – from 2002 through 2015 – are shown in the following tables. As explained in Trinity's report, the IMPROVE equation is applied to the concentration data to calculate light extinction (Mm^{-1}), and then light extinction is converted to haze index (dv).

Table 1. Haze Indices for Caney Creek

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	27.21	11.88
2003	26.54	10.74
2004	25.34	11.11
2005	29.21	12.93
2006	25.68	12.51
2008	23.70	9.24
2009	22.68	8.09
2010	22.94	10.76
2011	22.67	11.71
2012	21.49	9.54
2013	21.35	8.61
2014	20.72	8.52
2015	20.41	7.03

Table 2. Haze Indices for Upper Buffalo

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	26.74	12.83
2003	27.22	10.62
2004	25.58	10.74
2005	30.47	13.34
2006	25.42	13.00
2007	26.17	12.45
2008	24.60	10.49
2009	22.62	9.40
2011	23.21	11.51
2012	21.56	10.31
2013	21.25	8.60
2014	20.49	8.13
2015	19.96	7.50

The following figures illustrate how these measured values compare to the Uniform Rate of Progress ("URP") curves for each area. The figures are updates to Figures 3-3 and 3-4 of Trinity's report, and, as such, also show the projected haze index values based on the scenario-specific modeling summarized in Trinity's report.

Figure 1. Caney Creek Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index

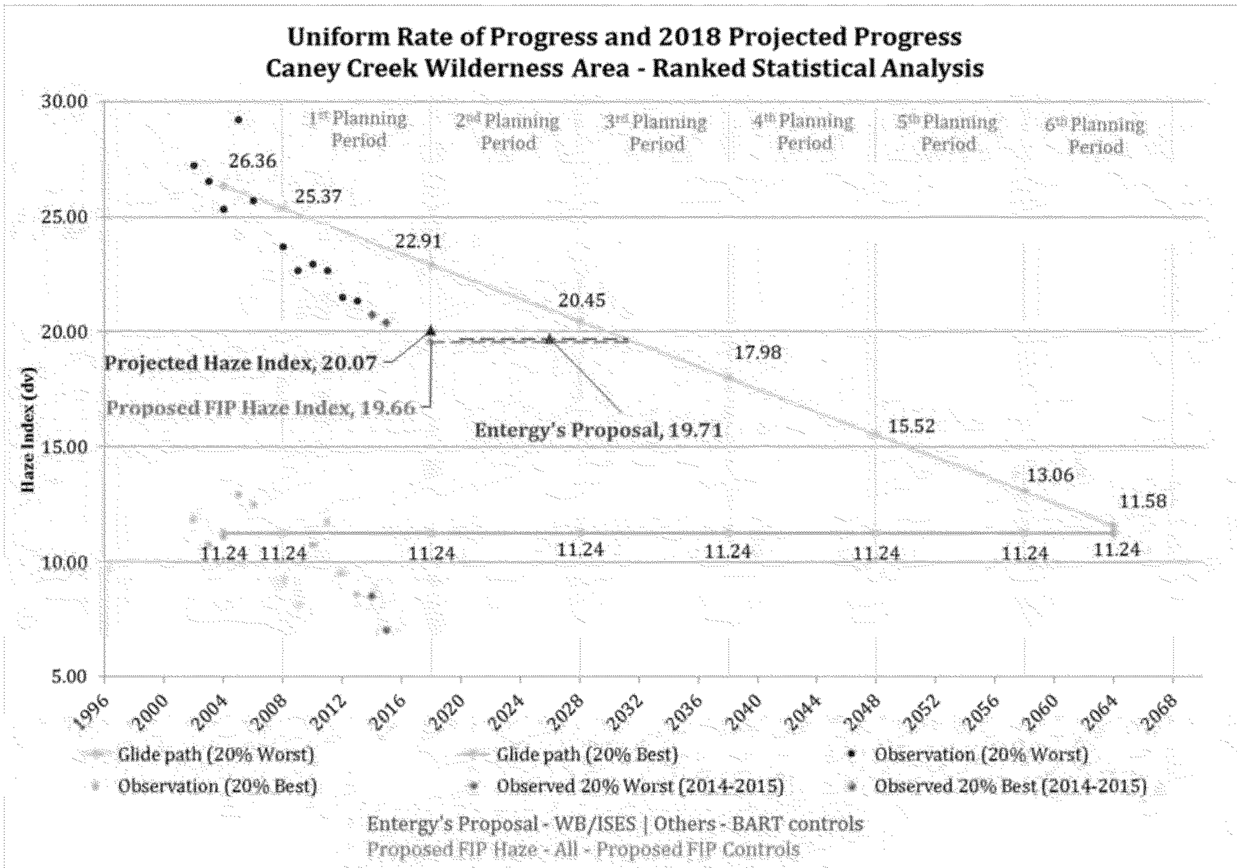
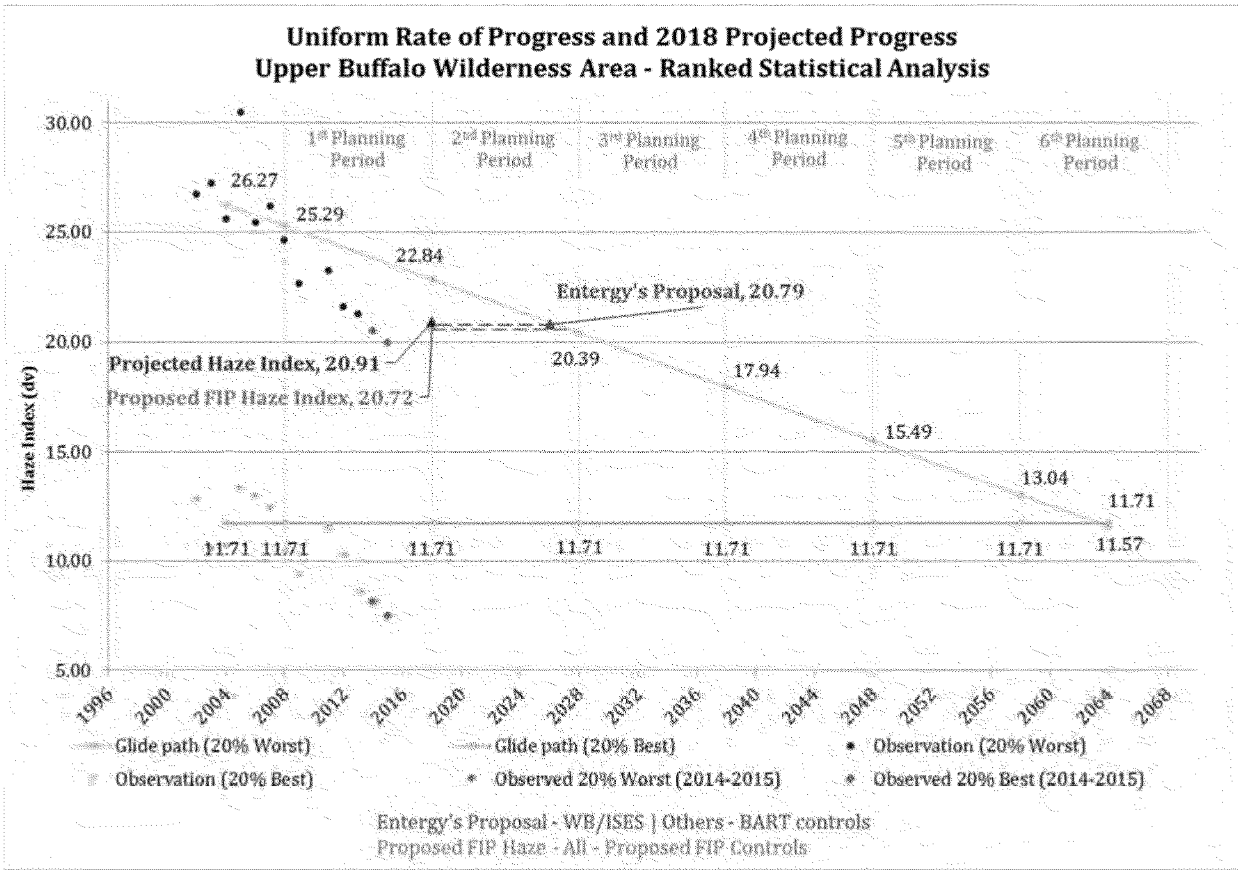


Figure 2. Upper Buffalo Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index



As shown above, the actual visibility impairment at CACR and UPBU have continued to decrease through 2015. The average 20 percent worst haze indices for CACR decreased from 21.49 dv in 2012 to 20.41 in 2015. Similarly, visibility improved at UPBU, where the average 20 percent worst haze indices decreased from 21.56 dv in 2012 to 19.96 dv in 2015. As shown in the figures and table below, these values are significantly less than (i.e., better than), and ahead of schedule of, the Reasonable Progress Goals (RPGs) proposed by ADEQ[1] of 22.48 dv by 2018 for the 20 percent worst days at CACR and 22.52 dv by 2018 for the 20 percent worst days at UPBU, and those finalized by EPA[2] of 22.47 dv for CACR and 22.51 dv for UPBU.

Table 3. 2018 Reasonable Progress Goals Compared to 2015 Visibility for the 20% Worst Days

Class I Area	ADEQ-Proposed RPG for 2018 (dv)	EPA-Finalized RPG for 2018 (dv)	Actual Visibility in 2015 (dv)
Caney Creek	22.48	22.47	20.41
Upper Buffalo	22.52	22.51	19.96

[1] Arkansas's 2008 Regional Haze State Implementation Plan (SIP).
[2] September 27, 2016 final Arkansas Regional Haze Federal Implementation Plan (FIP).

Figure 3. Caney Creek Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

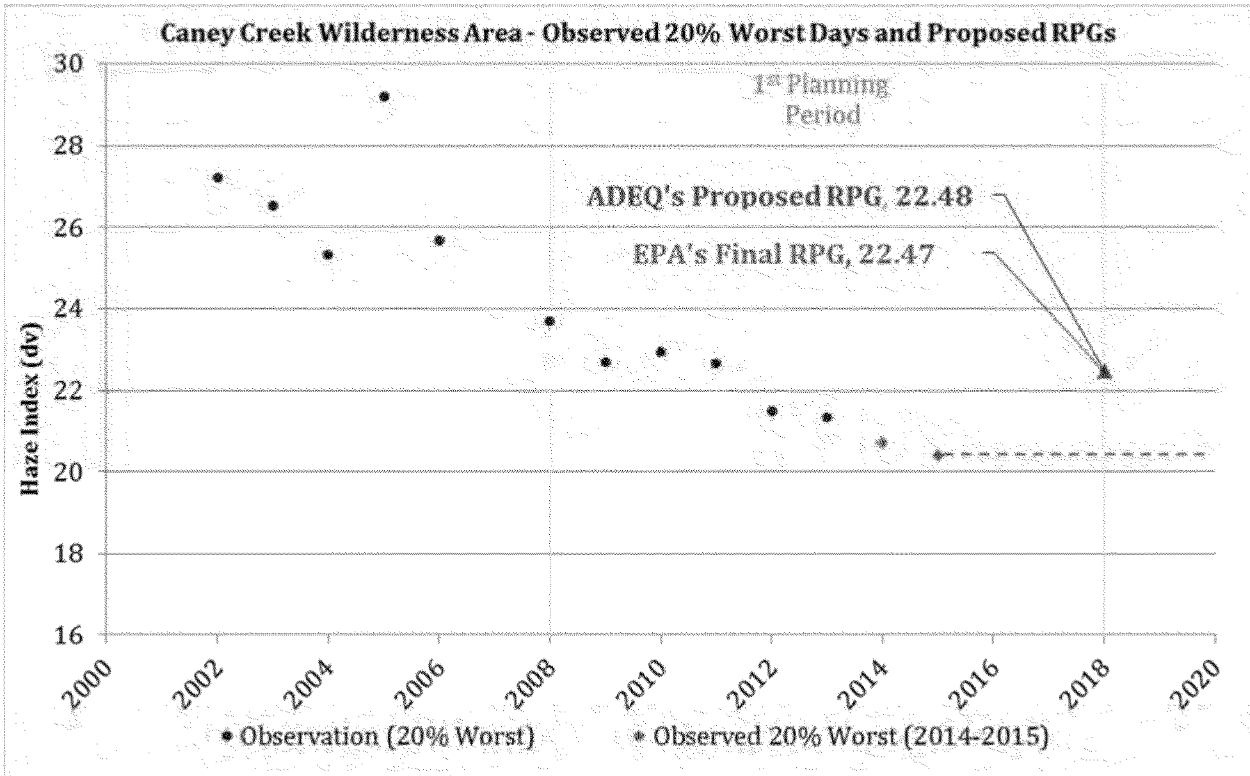


Figure 4. Upper Buffalo Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

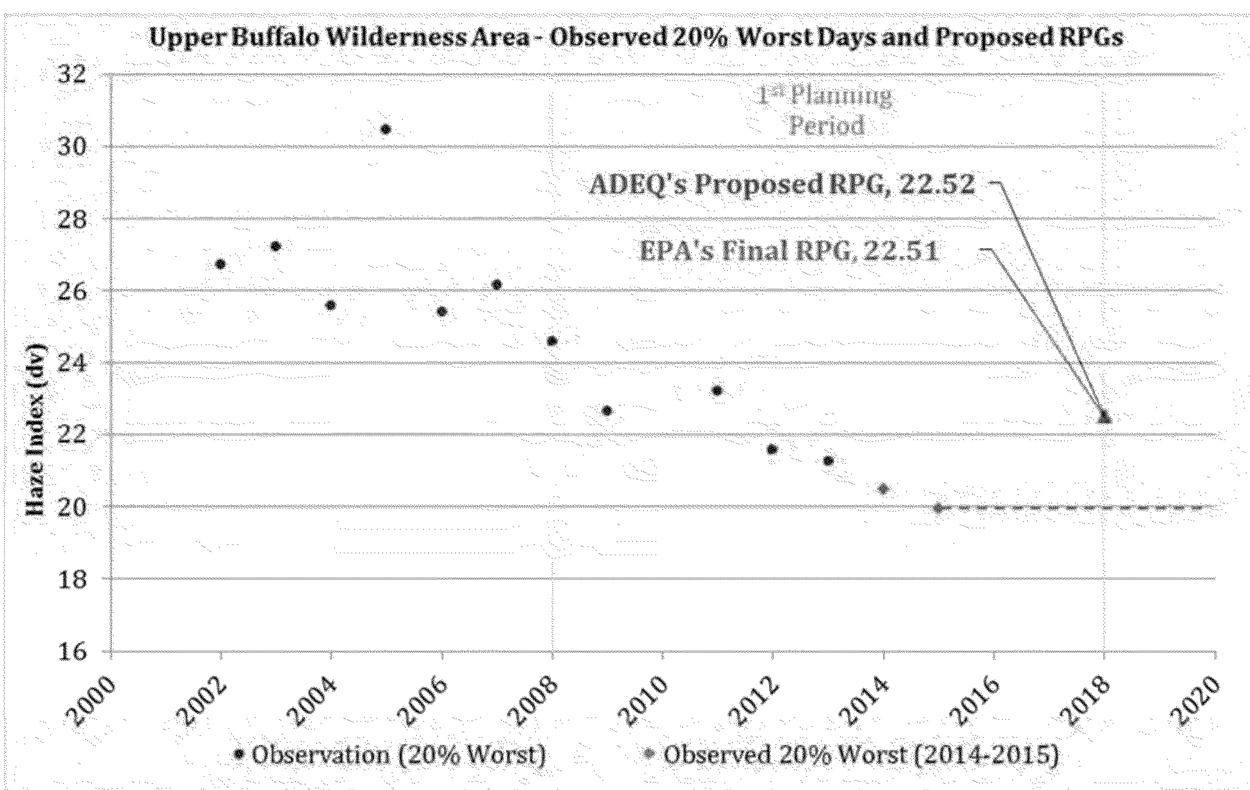


Exhibit B

Entergy Arkansas Inc.

Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 7, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov
Docket ID No. EPA-R06-OAR-2015-0189

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B. *White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015).

C. *Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. - Independence Plant*, Trinity Consultants (August 4, 2015).

D. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015).

E. *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Management Association (2002).

F. Excerpts from *Tangential Low NOx (TLN3) System for Entergy White Bluff Units 1 & 2*, Foster Wheeler North America Corp. Proposal to Entergy (Oct. 13, 2011).

G. Memorandum from Steve deMello, Project Manager, Amec Foster Wheeler North America Corp., to Michael P. Fallon, P.E., Entergy (July 30, 2015).

H. *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015).

I. Entergy Arkansas Inc.'s Comments on the Proposed Approval and Promulgation of Implementation Plans; Interstate Transport State Implementation Plan; Arkansas, Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility, Docket No. EPA-R06-OAR-2008-0633.

ENTERGY ARKANSAS INC.
COMMENTS ON THE PROPOSED REGIONAL HAZE
AND INTERSTATE VISIBILITY TRANSPORT
FEDERAL IMPLEMENTATION PLAN FOR ARKANSAS

EPA-R06-OAR-2015-0189

I. INTRODUCTION

On April 8, 2015, the U. S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 18,944, a proposed Federal Implementation Plan ("FIP") to address certain regional haze and visibility transport requirements for the State of Arkansas ("Proposed FIP" or "Proposal"). The Proposed FIP would address the requirements of the Regional Haze Rule and interstate visibility transport for those portions of Arkansas' State Implementation Plan ("SIP") that EPA previously had disapproved. *See* 77 Fed. Reg. 14,604 (Mar. 12, 2012). The Proposed FIP addresses the requirements for Best Available Retrofit Technology ("BART") for those sources for which EPA did not approve Arkansas' BART determinations, Reasonable Progress Goals ("RPGs"), reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA proposes to regulate under the FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). EPA is proposing sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") BART limits for White Bluff Units 1 and 2, and SO_2, NOx, and particulate matter ("PM") BART limits for the Auxiliary Boiler at White Bluff. EPA also is proposing a NOx BART limit for Unit 4 at Lake Catherine. Finally, EPA is proposing emissions limits at Independence to meet reasonable progress requirements and is seeking comment on two alternative options. Under Option 1, EPA is proposing SO_2 and NOx emission limits for Units 1 and 2 at Independence. Under Option 2, EPA is proposing only SO_2 emission limits for Units 1 and 2. EPA also is soliciting comment on any alternative control measures for White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for the current regional haze planning period.

In these comments, Entergy discusses its legal and technical concerns with the Proposed FIP. Entergy appreciates EPA's consideration of these comments, and urges EPA to make Entergy's suggested changes and issue a final FIP that provides visibility benefits without overly burdening EAI's customers and co-owners.

II. EXECUTIVE SUMMARY

The Regional Haze Program is intended to achieve gradual and steady improvement in visibility at Class I areas over the course of 64 years. The program was established under the Clean Air Act ("CAA") as a long-term program to allow major emitting sources to install controls or be phased out in a rational and economical manner to ultimately achieve natural visibility conditions at all Class I areas in the United States. The program also is intended to recognize that regional haze is a *regional* problem; one that benefits from broad programmatic changes and the retirement of sources as they reach the end of their useful lives. EPA's Proposed FIP for Arkansas largely abandons this approach, ignores the significant improvements in visibility in Arkansas' Class I areas that already have occurred, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose more than $2 billion in costs on EAI's customers and co-owners despite the lack of any need for, or benefit from, such a massive investment.

Entergy proposes a more reasonable, long-term, multi-unit approach to address regional haze in the Arkansas Class I areas that achieves reasonable progress, is consistent with the statutory scheme and allows Entergy to manage its generation fleet in a reliable and economic manner. In particular, Entergy proposes the following: (1) to achieve early SO_2 reductions by accepting lower SO_2 emission rate limitations at both White Bluff and Independence; (2) to achieve NOx reductions by installing NOx control technology on all four units within three years of the final FIP's effective date; and (3) to commit to the permanent cessation of coal-fired operations at White Bluff by 2028. Based on modeling by Entergy (which EPA should have conducted but failed to undertake), the difference in visibility at the Arkansas Class I areas between the proposed FIP controls and Entergy's proposal is imperceptibly small (*see* Section III.D.2 below) and does not warrant an investment of over $2 billion in scrubber technology at the plants.

Entergy's comments address a range of issues raised by the Proposal. Two issues are most critical. First, with respect to White Bluff, Entergy proposes to cease all coal-fired operations at the two coal-fired units in 2027 and 2028. This proposal necessarily changes the BART analysis for White Bluff. Because of Entergy's proposed commitment to stop burning coal, EPA's proposal to establish BART limits for White Bluff based on the installation of dry flue gas desulfurization ("FGD" or "scrubbers") must be rejected. Under the current schedule for finalizing the FIP, the scrubbers would not be installed until at least 2021, which would leave only six to seven years for EAI to recoup the approximately $1 billion in investment for dry scrubber installation. That cannot be justified economically or environmentally. Economically, the short amortization period would drive the costs of the scrubbers to over $7,500-$8,500 per ton of SO_2 removed. Environmentally, EPA projects that visibility will improve in each of Arkansas' Class I areas only by approximately one-fifth of a deciview ("dv") as a result of the proposed FIP controls on all sources in Arkansas; an amount that is absolutely undetectable. Controls on White Bluff would achieve merely a fraction of that amount.

Second, EPA's proposal to require SO_2 and NOx limits based on the installation of dry scrubbers and NOx controls on the two coal-fired units at Independence cannot be justified for the first planning period. Independence is not a BART-eligible source.[1] Accordingly, EPA may impose emission reduction requirements on Independence under the Regional Haze Program *only* to the extent *necessary* to achieve reasonable progress towards natural visibility levels. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits ... as may be *necessary* to make reasonable progress") (emphasis added). The visibility in Arkansas' Class I

[1] Despite the fact that Independence is not a BART-eligible source under the Clean Air Act, EPA's analysis in the Proposal essentially and improperly treated it as such.

areas already has improved substantially in the past 10 years such that the haze index for both Class I areas currently is well below the uniform rate of progress ("URP" or "glide path") that EPA uses to ensure reasonable progress towards natural visibility conditions and that EPA had previously approved for Arkansas.[2] Based on the negligible visibility benefit from installing scrubbers at Independence, the cost of the controls is an astounding $1.33 billion to $1.53 billion per deciview improvement. *See* Section III.C.3 below. Scrubbers at Independence are simply not necessary to ensure that visibility in Arkansas' Class I areas remains below the URP, nor are they justifiable based on EPA's own analysis of the visibility benefits resulting from such a huge investment.[3]

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment ("IMPROVE") data, which reflects monitored visibility impairment in Class I areas, the haze index for the 20% worst ("W20") days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association ("CENRAP"),[4] all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards ("MATS") rule,[5] the continuing benefits of the Clean Air Interstate Rule ("CAIR"), the next phase of the Cross State Air Pollution Rule ("CSAPR"), and implementation of the soon-to-be-released revised 8-hour ozone National Ambient Air Quality Standards ("NAAQS"), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of BART controls, and Entergy's proposed interim controls and proposed commitment to cease coal burning at White Bluff, no further action will be necessary to ensure that Arkansas' Class I areas remain below the URP until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

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[2] 76 Fed. Reg. 64,186, 64,194-95 (Oct. 17, 2011).

[3] The Class I areas outside of Arkansas that are potentially affected by emissions from Arkansas, similarly, are below the URP and do not need additional reductions to achieve reasonable progress or their long-term visibility goals.

[4] CENRAP is a regional planning organization that includes nine states – Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[5] In spite of the Supreme Court decision in *Michigan v. EPA*, 135 S.Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units ("EGUs"), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, Entergy expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

EPA acknowledges that controls on Independence are not needed for Arkansas to achieve the URP. 80 Fed. Reg. at 18,992 ("We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period."). Indeed, after the proposed BART controls are installed and White Bluff ceases coal-fired operations, Arkansas sources will not approach the URP, or glide path, for at least another decade. Entergy's analysis, based on the actual visibility impairment data, shows that Caney Creek will remain below the glide path until at least 2032 and Upper Buffalo until at least 2028 with no additional controls on in-state sources. *See* Section III.D.2 below (Figures 13 and 14). Imposing controls on Independence is simply not necessary or justified to achieve reasonable progress towards natural visibility in Arkansas' Class I areas.

EPA's reasonable progress analysis and justification for proposing stringent emission limitations at Independence are not legally defensible under the Regional Haze Program based on the costs and lack of visibility benefits of the proposed limits. EPA suggests it is only logical to require Independence to install controls because its SO_2 emissions are large and because it would be cost effective to control them. Cost effectiveness is a factor in deciding the degree of controls necessary to establish RPGs, but it is not an independent basis for imposing controls and does not determine reasonable progress goals. In this case, installing the controls on Independence that would be necessary to meet the proposed emission limits will cost EAI's customers and co-owners in excess of $1 billion. While the cost per ton of SO_2 removed may be within the range that might support a BART determination, it is nonetheless high in the context of reasonable progress controls, particularly where the benefits are small and reductions are not needed to demonstrate that Arkansas is making reasonable progress towards achieving natural visibility conditions at its Class I areas. Accordingly, Entergy objects to the RPGs that EPA is proposing for Arkansas.

EPA also improperly relied on CALPUFF modeling to justify the proposed controls at Independence, vastly overstating the impact of emissions from Independence and the benefits of installing controls. CALPUFF modeling, a single source puff model, is not an appropriate model to determine or project reasonable progress benefits. Reasonable progress is determined by evaluating the overall visibility values in Class I areas and the projected trends in visibility as a result of emissions, controls and operations at all sources contributing to visibility impairment. EPA has recognized in recent rulemakings that CALPUFF cannot do this and it is therefore arbitrary and capricious for EPA to rely on CALPUFF for this purpose here.

Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term. Entergy proposes to meet more stringent SO_2 limits at both White Bluff and Independence beginning in 2018. In addition, Entergy proposes to install low NOx burners ("LNB") and separated overfire air ("SOFA") on both White Bluff and Independence within three years of the final FIP's effective date, assuring that there will be both near-term and long-term visibility benefits.

III. COMMENTS

A. Entergy Proposes To Cease Coal-Fired Operations At White Bluff By 2028 As Part Of A Long-Term, Multi-Unit Regional Haze Plan.

EPA's proposed BART determination for White Bluff appears to be based, in general, on the White Bluff five-factor BART analysis that Entergy provided to the Arkansas Department of Environmental Quality ("ADEQ") in October 2013 ("Revised White Bluff BART Analysis"),[6] which assumed White Bluff Units 1 and 2 would continue to combust coal for the foreseeable future. As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect.[7]

As a result of Entergy's proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable. Entergy's proposal for White Bluff requires EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units. In addition, EPA used outdated costs in its BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation. When the appropriate dry scrubber costs are considered along with the units' remaining useful coal-fired life, the average cost effectiveness of dry FGD increases to a range of over $7,500 to $8,500 per ton at the White Bluff units, costs that are far too high to constitute BART.

1. EPA must take the remaining useful life of the White Bluff units into account in the BART analysis.

The CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.

> If the remaining useful life exceeds the amortization period, then the remaining useful life has essentially no effect on the control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, [EPA advises] us[ing] this shorter time period in [the BART] cost calculations.

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[6] Revised BART Five Factor Analysis, White Bluff Steam Electric Station (Oct. 2013), EPA Docket ID EPA-R06-OAR-2015-0189-0045. *See* 80 Fed. Reg. at 18,969-75. However, Entergy is confused by EPA's references in the Proposal to AEP's modeling and assumptions with respect to the BART analysis for White Bluff. *See id.* at 18,969. The references to AEP make it unclear whether EPA actually used Entergy's Revised White Bluff BART Analysis in evaluating the BART controls for White Bluff. EPA needs to confirm that it reviewed and analyzed Entergy's Revised White Bluff BART Analysis.

[7] Entergy anticipates that its compliance with a final FIP, including installing dry scrubbers or, in the alternative, ceasing coal-fired operation at White Bluff, will be subject to Arkansas Public Service Commission hearing and review.

Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, App. Y, Section IV.D.4.k ("BART Guidelines").

BART controls that may be cost effective using the standard amortization period (typically 20-30 years) may no longer be cost effective when a source's remaining useful life is factored into the analysis. *See* 79 Fed. Reg. 74,818, 74,837 (Dec. 16, 2014) ("Proposed Texas Regional Haze FIP") ("[CENRAP] noted that for sources with a relatively short remaining useful life, this consideration would have weighed more heavily against a determination that controlling those sources would have been reasonable.").

EPA determined that remaining useful life was not a meaningful factor for White Bluff given Entergy's previous plans to continue coal-fired operation at White Bluff. *See* 80 Fed. Reg. at 18,971, Tables 34 and 35 (using 30 years and the life of the equipment); Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD), at 16 ("we typically assume a 30 year equipment life for scrubbers, as we do here."). As a result, EPA concluded that dry scrubbers on White Bluff would have an average cost effectiveness at Unit 1 of $2,227/ton and at Unit 2 of $2,101/ton. 80 Fed. Reg. at 18,971, Table 32. These cost estimates were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. *EPA Air Pollution Control Cost Manual* (Jan. 2002) ("Control Cost Manual").[8]

Now, however, given Entergy's proposed commitment to cease coal-fired operation at White Bluff by 2027-2028, EPA will need to revise its BART analysis to take the remaining useful life of the units into account. The CAA requires that BART controls be installed "as expeditiously as practicable," but no later than five years from approval of a regional haze SIP or the issuance of a FIP. 42 U.S.C. § 7491(b)(2)(A), (g)(4); 40 C.F.R. § 51.308(e)(1)(iv). In this case, EPA has stated that it is unable to finalize the FIP until after December 15, 2015,[9] which means that any final FIP cannot have an effective date earlier than sometime in 2016. Thus, the scrubbers would be installed and operational, at the earliest, in 2021.[10] In light of Entergy's proposed commitment to cease coal-fired operations at the units in 2027 and 2028, the amortization period will be approximately six to seven years. This has a significant impact on the cost calculation, resulting in much higher costs compared to the emissions reductions achieved.

[8] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

[9] EPA's Response to Letter/Order (Dkt. No. 52) at 2, *Sierra Club v. McCarthy*, No. 14-cv-00643 (Jul. 15, 2015 E.D.Ark.).

[10] EPA has proposed to allow White Bluff the full five years to install the scrubbers and meet the BART SO_2 emission limits. 80 Fed. Reg. at 18,973. Entergy agrees with EPA that such major emissions control technology could not be designed, contracted for, and installed any earlier than five years from the effective date of the final regional haze FIP.

2. EPA's analysis of the costs to install dry scrubbers at White Bluff is replete with errors and artificially improves the cost effectiveness of scrubber installation at White Bluff.

EPA's analysis of the cost and cost effectiveness of installing dry scrubbers at White Bluff contains numerous flawed methodologies, incorrect assumptions and mistakes, all of which seem designed to artificially lower the actual costs of installing dry scrubbers and improve the supposed cost effectiveness of the controls. Sargent & Lundy ("S&L") has undertaken a thorough analysis of EPA's SO_2 Cost TSD and provided a report, *Report of EPA's Cost Analysis Arkansas Regional Haze Proposed Federal Implementation Plan*, No. SL-012913, Sargent & Lundy (July 2015) ("S&L FIP Cost Report") (attached as Exhibit A and incorporated by reference herein). The S&L FIP Cost Report demonstrates that EPA incorrectly specified the SO_2 emissions baseline for White Bluff, which increased expected emissions. EPA then improperly used maximum monthly emissions to estimate the tonnage reduction achievable with the scrubbers to reduce the cost per ton, and incorrectly eliminated approximately $100 million in costs that EPA's own Control Cost Manual says should be included.

(i) EPA arbitrarily eliminated two of five years in calculating baseline emissions for White Bluff.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, Section IV.D.4.d.1. In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period. Entergy originally had used the 2001 - 2003 baseline period. *See* Revised White Bluff BART Analysis at 4-1. EPA looked at the five-year period between 2009 and 2013, SO_2 Cost TSD at 13, Table 7, but inexplicably excluded the maximum and minimum years during this five-year period. *Id.* The effect of excluding these two years is to increase artificially the emissions baseline for White Bluff. S&L FIP Cost Report at 3. There is no reasoned explanation for excluding two of the five recent years' of emissions data in calculating the baseline. EPA should use the average emissions from all five years to determine the baseline as it is more representative of the anticipated annual emissions from the White Bluff units.

(ii) EPA uses an incorrect methodology that artificially inflates the SO_2 emission reductions achievable with scrubbers.

After having incorrectly identified the baseline emissions for White Bluff, EPA then apparently ignores the baseline emissions when estimating the SO_2 reductions that are achievable with the scrubbers. In an apparent attempt to inflate the emission reductions achievable at White Bluff through the installation of scrubbers, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 for each unit and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. *See* White Bluff_R6 cost revisions2.xlsx, "Cost Effectiveness" tab, EPA Docket ID EPA-R06-OAR-2015-0189-0093. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. *Id.* This methodology is patently incorrect. It assumes the baseline emissions are based on maximum monthly averages, which significantly overstates the annual averages actually used to calculate baseline emissions.

To correctly estimate the SO_2 emission reductions, EPA must multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the five-year baseline period. S&L FIP Cost Report at 3. As detailed in the S&L FIP Cost Report, EPA's inappropriate use of maximum monthly emission rates overstates the achievable emission reductions at White Bluff by between 150 and 900 tons per year. *Id.* at 4, Table 2.

(iii) EPA improperly underestimates the costs by approximately $200 million to justify scrubbers at White Bluff.

EPA based its cost calculations for dry FGD on the costs provided by Entergy in its Revised White Bluff BART Analysis, and presented its analysis of the costs for scrubber installation at White Bluff in its SO_2 Cost TSD. However, EPA's analysis is full of errors, which resulted in an underestimation of the scrubber costs at White Bluff by approximately $200 million.

First, the costs in the Revised White Bluff BART Analysis are significantly outdated, and EPA failed to adequately account for this factor in its analysis. The costs for a dry scrubber provided in the Revised White Bluff BART Analysis were based on (1) a study provided to Entergy by S&L in 2009, which provided a line-itemized cost estimate that included contractor equipment, material, and labor costs for two semi-dry scrubbing systems; and (2) costs provided by Alstom in December 2009 to supply two semi-dry scrubbing systems, escalated by 10% based on updated price information from Alstom. SO_2 Cost TSD, at 2. However, even with the updated cost information from Alstom, the information provided in the Revised White Bluff BART Analysis is now at least five years out of date and significantly undervalues the costs of installing dry scrubbers at White Bluff. EPA attempted to address this issue by escalating the Alstom cost information to 2013 dollars using the Chemical Engineering Plant Cost Indices ("CEPCI"). However, EPA's use of the CEPCI inadequately escalated the projected vendor costs. According to S&L, EPA underestimated escalation significantly using the CEPCI – by over $36 million – rather than using updated vendor pricing. S&L FIP Cost Report at 11. Further, this underestimation of the cost escalation was carried throughout EPA's analysis in the SO_2 Cost TSD and resulted in a total underestimation of the costs for scrubber installation of over $85 million. *Id.* at 12, Table 7.

Second, EPA improperly excluded from the cost calculation legitimate costs that Entergy would incur to install dry scrubbers at White Bluff. EPA incorrectly eliminated over $115 million in costs from Entergy's cost analysis. *See* S&L FIP Cost Report at 8, 10. EPA mistakenly assumed certain Balance of Plant ("BOP") costs were included in the Alstom scope of work, so it eliminated these costs as duplicative. As the S&L FIP Cost Report explains, EPA improperly eliminated several BOP costs from Entergy's cost analysis:

- costs for the reagent handling system;
- costs for the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney;

- the costs to apply an acid resistant coating to the chimney shell to protect the concrete from downwash effects;

- the costs associated with replacing the continuous emissions monitoring systems ("CEMS") and associated recalibration and testing costs; and

- costs calculated as percentages of the BOP equipment, material and labor costs.

Id. at 7-8. In total, by eliminating these costs, EPA underestimated the BOP costs by approximately $31 million. *Id.* at 8. EPA also suggested that the costs for one absorber vessel could be eliminated but cited no basis for its assumption that two absorber vessels are adequate for White Bluff. Entergy disagrees with EPA's assumption regarding the number of absorber vessels for White Bluff. *See* S&L FIP Cost Report at 17.

EPA also eliminated approximately $41.7 million for Entergy's Owner's costs,[11] despite the fact that such costs are allowed under EPA's Coal Quality Environmental Cost ("CUECost") model. *Id.* at 10. EPA claimed that such costs had not been documented, were duplicative of other costs or did not appear to be valid costs under the Control Cost Manual methodology. 80 Fed. Reg. at 18,971. For example, EPA improperly eliminated Entergy's capital suspense costs without explaining why such costs were duplicative of other costs or not valid under the Control Cost Manual methodology. Capital expenditure costs include both direct assigned and allocated expenses. Allocated expenses represent overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function at Entergy charges its overhead costs to a "Capital Suspense" project, which is then allocated to the appropriate capital project. Capital suspense, therefore, is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and Administrative and General ("A&G") (Corporate Accounting) rates. Because capital suspense costs are a portion of total capital expenditure costs, these costs are not duplicative of other costs.[12] For example, capital suspense costs do not include labor, administrative, and related elements that are present in Entergy's Internal Control costs. *See* SO_2 Cost TSD at 9. It was entirely proper for Entergy to include these costs in its control technology cost estimates. According to EPA's Control Cost Manual, overhead costs should be counted in the total annual cost of a project. Total annual cost is comprised of direct costs, indirect costs, and recovery credits. Control Cost Manual at 2-7. Indirect costs specifically include overhead costs. *Id.* at 2-8; 3-32.

Third, EPA significantly under-estimated the direct Operating and Maintenance ("O&M") costs projected for the scrubbers by using its Integrated Planning Model ("IPM") Spray Dryer Absorber ("SDA") cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. *See* SO_2 Cost TSD at 14, Table 8. The IPM model includes several assumptions that fail to take into account site-specific factors. S&L FIP Cost Report at 13-14. Accordingly, the IPM model is not consistent with the BART Guidelines,

[11] These same improper exclusions were made with respect to EPA's analysis of BART controls for NOx at White Bluff and Lake Catherine Unit 4.
[12] Entergy had previously supplied this information on capital suspense costs to EPA. *See* 80. Fed. Reg. at 18,971, n. 55.

which requires a source-specific evaluation of controls costs. BART Guidelines, at Section IV.D.5 . EPA also erroneously scaled the indirect annual costs, all of which were estimated as percentages of capital cost, by using a scaling factor that did not depend at all on the capital costs. *See* S&L FIP Cost Report at 17.

Fourth, in the design for the dry scrubbers, the Revised White Bluff BART Analysis had assumed that White Bluff would burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which is in excess of the sulfur level of the coals the units have historically burned. EPA criticized Entergy for this assumption and revised the White Bluff baseline emission rates and projected post-control emission rates used for the cost effectiveness analysis. *See* SO_2 Cost TSD at 12-14. However, it is proper, when conducting a BART cost analysis, to consider future fuel flexibility. The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2005) (codified at 40 C.F.R. Part 51 App. Y). Although the BART Guidelines explain that anticipated annual emissions are *generally* estimated based on annual emissions from a baseline period assuming conditions of past practice, *id.* at 39,167-68, EPA has approved BART determinations that assume "worst-case coal scenarios." *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sept. 21, 2011). Hourly CEMS data confirm that EPA's selection of 0.68 lb/MMBtu as the design basis for the capital costs is completely inadequate and would not achieve compliance with the FIP-proposed emission limit of 0.06 lb/MMbtu unless fuel sulfur limitations were imposed. Based on historical data and potential fuels that can be fired at White Bluff, 1.2 lb/MMBtu is an appropriate fuel sulfur level to design dry FGD systems for White Bluff. *See* S&L FIP Cost Report at 15-16.

If Entergy were constrained as to the type of coal that it could burn at White Bluff after the installation of controls, it would be necessary to reflect such a constraint in the cost of compliance, as it would force Entergy to continue purchasing higher-cost, low sulfur coal. Historically, Entergy has purchased lower sulfur coal than required by permit to ensure full compliance with applicable emission rates and to minimize costs of compliance with market-based emission programs. If White Bluff were to install BART controls, such considerations would become less meaningful and lower-cost, higher sulfur coal would enable Entergy to meet its BART obligations for less cost. Nonetheless, in the S&L FIP Cost Report, S&L used White Bluff's current emission rate of 0.68 lb/MMBtu to evaluate site-specific O&M costs. S&L FIP Cost Report at 15.

Finally, although Entergy removed Allowance for Funds Used During Construction ("AFUDC") from the final Revised White Bluff BART Analysis in response to comments from EPA on the Proposed White Bluff BART Analysis, Entergy disagrees with EPA that AFUDC should not be considered in the control costs.[13] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach $30 million to $60 million during the 30-46 months of construction that would be needed to install

[13] As noted in the Revised White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future cost control analyses. Revised White Bluff BART Analysis, at 5-4.

major control equipment such as scrubbers on a large unit. AFUDC includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs and it was appropriate for Entergy to have initially included AFUDC in the White Bluff control costs. In its comments on the Proposed White Bluff BART Analysis, EPA claimed that AFUDC is not allowed by EPA's Control Cost Manual because "the CCM uses overnight costing methodology." EPA Region 6 Comments on White Bluff BART Analysis, at 1 (Aug. 21, 2013) EPA Docket ID EPA-R06-OAR-2015-0189-0044. However, contrary to EPA's assertion, the Control Cost Manual does not even address the use of the overnight methodology as being the basis for estimating costs. *See* S&L FIP Cost Report at 6. In fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable. Control Cost Manual at 1-32, 2-44. The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but instead is an explicit recognition of that category of costs.

EPA also has claimed that the U.S. Energy Information Administration ("EIA") uses overnight costs to project plant costs. *See* S&L FIP Cost Report at 6. However, this is a mischaracterization of the EIA methodology. According to EIA, "[s]tarting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, at 2, n.2 (Nov. 2010).[14] Despite EPA's claims, the Control Cost Manual does not preclude inclusion of AFUDC and the EIA specifically takes such costs into account for an electric generating unit. Accordingly, the costs of controls for dry scrubbers at White Bluff should appropriately include AFUDC.

3. The costs for dry scrubbers at White Bluff, based on current estimates, are too high to constitute BART.

EPA's use of outdated costs in its cost calculation, its exclusion of certain legitimate costs for the construction of dry scrubbers, and its failure to take into consideration fuel flexibility at White Bluff renders EPA's analysis artificially low and inappropriate for evaluating the cost effectiveness of dry scrubbers on White Bluff for regional haze purposes. To correct EPA's deficiencies, Entergy commissioned a revised dry FGD cost analysis from S&L that takes into account the current costs for dry scrubber installation as compared to the costs that would have been incurred in 2009 or 2010. *See White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015) ("2015 S&L FGD Report") (attached as Exhibit B and incorporated by reference herein). The 2015 S&L FGD Report also takes into account site-specific factors at White Bluff that have an effect on costs. Finally, the study also uses the current SO_2 emission rates at White Bluff for the O&M costs. For the capital cost estimate, S&L uses a design basis of 1.2 lb/MMBtu sulfur coal. As explained in the S&L FIP Cost Report, the current maximum monthly average emission rates are not an appropriate basis for sizing the scrubbers. The equipment must be sized to handle the maximum short-term emission rate. S&L FIP Cost Report at 14-15.

[14] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

The Revised White Bluff BART Analysis had estimated the costs to install dry scrubbers at White Bluff to be approximately $670 million. Revised White Bluff BART Analysis, at 5-6, Table 5-3. The 2015 S&L FGD Report estimates that the total costs of dry scrubbers at White Bluff will be in excess of $1 billion. 2015 S&L FGD Report at ES-1. When the remaining useful coal-fired life of these units is factored into the analysis, dry FGD installation at White Bluff would be indisputably cost-prohibitive.

Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six to seven years would result in an average cost effectiveness of **$7,689-$8,599**/ton at Unit 1 and of **$7,642-$8,546**/ton at Unit 2. S&L FIP Cost Report at 23, Table 11. EPA has determined costs of substantially less than this magnitude to be cost-prohibitive on numerous occasions, including in this very same rulemaking. For example, for AECC McClellan Unit 1, even though EPA claimed that "[s]witching to diesel is projected to result in considerable visibility improvement," EPA rejected SO_2 BART limits based on switching to diesel because EPA determined that diesel, with an average cost effectiveness of $7,145/ SO_2 ton removed, was not "cost-effective in view of the incremental visibility improvement." 80 Fed. Reg. at 18,959. EPA also rejected combustion controls as NOx BART for AECC McClellan Unit 1 based on an average cost effectiveness of $6,261/NOx ton removed, which, according to EPA "is not within the range of what we generally consider to be cost-effective." *Id.* at 18,961. Further, EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,091/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,331-33; Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. at 58,630; Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012). Notably, although EPA found that dry sorbent injection was cost effective on a cost-per-ton basis, 77 Fed. Reg. at 24,047, EPA concluded that the costs were not justified by the visibility improvement, which it calculated to be $30 million per deciview. 77 Fed. Reg. at 57,895. This is magnitudes lower than the cost-per-deciview of dry FGD at White Bluff Units 1 and 2, which, for Unit 1, would be approximately **$3.1 billion** per deciview at Caney Creek and **$2.7 billion** per deciview at Upper Buffalo and, for Unit 2, approximately **$2.9 billion** per decivew at Caney Creek and **$2.6 billion** per deciview at Upper Buffalo.[15]

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[15] These numbers were calculated from the deciview improvement attributable to White Bluff Units 1 and 2 based on EPA's "scaling methodology." *See* 80 Fed. Reg. 18,997. This methodology results in an improvement at Caney Creek of .036 dv from Unit 1 and .038 from Unit 2 and an improvement at Upper Buffalo of .040 from Unit 1 and .043 from Unit 2. Even if the deciview improvements projected from EPA's CALPUFF modeling were used, *see* 80 Fed. Reg. at 18,972, the $/deciview calculation would not support the installation of dry FGD as BART at White Bluff. Entergy estimates that the costs based on the CALPUFF modeled improvement for Unit 1 would be approximately $135 million per deciview at Caney Creek and $144 million per deciview at Upper Buffalo and, at Unit 2, the costs would be approximately $145 million per deciview at Caney Creek and $143 million per deciview at Upper Buffalo.

The CAA requires that a BART determination consider the degree of anticipated visibility improvement. 42 U.S.C. § 7491(g)(2). Accordingly, EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). However, EPA's proposed controls do exactly this. The improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 based on EPA's scaling methodology are only a fraction of a deciview. Even the CALPUFF predicted visibility improvements at Caney Creek and Upper Buffalo from the installation of dry FGD at White Bluff Units 1 and 2 are less than 1 deciview from each unit, *see* 80 Fed. Reg. 18,972, making them imperceptible to the human eye. *See* Section III.C.2.iii below. The massive cost of installing dry scrubbers at White Bluff to achieve these insignificant improvements, whether on a dollar per deciview basis or a dollar per ton basis, would be *much higher* than the costs that EPA has previously rejected as BART and that EPA proposes to reject as BART in this Proposed Rule. Accordingly, the installation of dry scrubbers cannot be considered BART for SO_2 at White Bluff.

4. Emissions reductions at White Bluff will be achieved through interim controls.

In addition to its plan to cease combusting coal at White Bluff by 2028, Entergy proposes to meet interim SO_2 emission rate reductions prior to 2028 through a reduction in the units' permitted SO_2 emission rates. The units currently have a permitted 3-hour average SO_2 limit of 1.2 lb/MMBtu. Entergy proposes to lower this limit to a rolling 30-day average limit of 0.6 lb/MMBtu beginning in 2018.

NOx BART for all EGUs in Arkansas, including White Bluff, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). EPA has proposed to take this same approach in the Texas Regional Haze FIP and has approved several state regional haze SIPs that adopted this approach. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,821; *see also* Proposed Pennsylvania SIP Approval, 80 Fed. Reg. 2,841, 2,844 (Jan. 21, 2015); Final Minnesota SIP Approval, 77 Fed. Reg. 34,801, 34,801-02 (June 12, 2012). EPA should adopt this same approach in the final Arkansas Regional Haze FIP and provide that compliance with CSAPR is NOx BART for all of Arkansas' EGUs.

However, in the event EPA continues to require Arkansas' EGUs to meet source-specific NOx BART limits in the final FIP, Entergy proposes that the units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr. This limit is based on the installation of LNB/SOFA and Entergy would be prepared to meet this limit no later than three years from the effective date of the final rule.[16] *See* 79 Fed. Reg. at 18,974-75. Although the cost effectiveness

[16] As explained further in Section III.E below, this limit is different from the limit that Entergy proposed as NOx BART in its Revised White Bluff BART Analysis. The revised limit is necessary due to the changed operating conditions at White Bluff over the past few years. The plant is now economically dispatched through the Midcontinent Independent System Operator ("MISO") and is spending greater amounts of time at lower load than it did in 2013, when the Revised White Bluff BART Analysis was submitted to ADEQ, and in prior years. The emissions guarantee that Entergy received from Foster Wheeler, the vendor that Entergy has selected to supply the NOx control technology, only applies to loads of 50% of capacity or greater. Therefore, a revised limit is necessary

of installing LNB/SOFA would significantly decrease as a result of a revised remaining useful life analysis for the units, if EPA does not adopt its CSAPR equals BART approach for Arkansas, Entergy is prepared to install these controls as part of its comprehensive visibility improvement proposal.

This combination of CSAPR compliance or, in the alternative, LNB/SOFA installation, and acceptance of a lower SO_2 emission rate through the remaining useful coal-fired life of the White Bluff units should be determined to be BART for White Bluff. No additional controls are justified given Entergy's proposal to limit the number of years of coal-fired operation at White Bluff.

B. EPA's Reasonable Progress Analysis And Proposed Determination Are Inconsistent With Other Regional Haze Development Processes.

1. EPA's reasonable progress analysis does not follow prior actions.

For reasonable progress purposes, EPA failed to undertake an appropriate reasonable progress analysis, including the crucial first step of determining whether additional controls are, in fact, necessary for Arkansas to make reasonable progress. *See* Section III.C below. EPA targeted only Independence in its analysis and subsequent decision to impose SO_2 and NOx limitations on the two coal-fired units at Independence. By focusing solely on Independence, EPA's reasonable progress analysis for the proposed Arkansas FIP abandons the analytical approach and determinative standards that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA established in its own guidance or utilized and applied in previous approvals/disapprovals of regional haze SIPs or promulgation of regional haze FIPs, EPA made the arbitrary decision to review Independence simply because it believes "it would be unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992. EPA failed to consider any lesser level of controls, the relative costs of such controls, the effectiveness of the controls in improving visibility or the cost per deciview improvement associated with the proposed controls.

EPA arbitrarily elected to propose controls for Independence that are unnecessary for Arkansas to demonstrate reasonable progress, provide no perceptible visibility improvement and exceed the cost estimates documented for other sources under other approved plans where EPA declined to impose reasonable progress controls. Further, EPA failed to follow its own guidance, which indicates that "States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment." *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, at 3-2 (June 1, 2007) ("Reasonable Progress Guidance").[17] The arbitrary evaluation process that EPA followed in the Proposal not only distorts the goals and objectives of the Regional Haze Program, but it also is contrary to EPA's own requirements for uniformity and regional consistency.

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to ensure that the White Bluff units can comply with the NOx limit at the lower loads that have become a more common operating condition for the units.

[17] Available at http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf

(i) EPA failed to determine visibility impact and the scope of Arkansas sources' contribution to visibility impairment.

EPA's singular attention on Independence for reasonable progress controls is unsubstantiated and is patently arbitrary and capricious. Despite identifying the 10 largest point sources of SO_2 and NOx within Arkansas, EPA focused only on the top three: White Bluff, Independence, and Flint Creek. Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls are necessary at those sources and the subsequent reasonable progress analysis fell solely on Independence. *Id.* at 18,991-92. Other than stating that these plants are the three largest sources, EPA provides no explanation for ignoring the other seven large point sources.[18]

EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence, is contrary to past rulemakings and is completely inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the regional haze FIP for Texas. *See generally*, Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818. There, the Agency completed a multi-step evaluation that included: Q/D analysis (i.e., total emissions – 24-hour maximum annualized – divided by distance to the Class I area) for each Texas point source and relevant Class I area to identify those point sources requiring further evaluation,[19] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis,[20] and an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement.[21] This analysis was key to the development of EPA's approach for proposing appropriate controls by indicating for which sources the installation of controls are needed and would be worthwhile. *See id.* at 74,839 (explaining that the results "suggest that controlling a small number of sources will result in visibility benefits at both Class I areas, and that rather than evaluating controls at all facilities identified by Texas combined, a subset of those facilities (and some additional facilities not identified) may be reasonable.").

EPA took this same approach in other states. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058-59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. By notable contrast, EPA's Region 6 office did not perform *any* evaluation to identify *any* Arkansas point sources contributing to visibility impairment (or the scope of contribution) at Caney Creek or Upper Buffalo. EPA also performed multi-source emissions analysis using CAMx in most of those other states rather than looking only at the potential impact on visibility using the CALPUFF,

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[18] EPA must provide a reasoned basis for failing to analyze whether these other emission sources should be evaluated for reasonable progress purposes. Indeed, EPA should have conducted multi-source modeling to demonstrate that the other six largest point sources in Arkansas do not contribute to visibility impairment in the Arkansas Class I areas.

[19] *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)*, Appendix A at A-4 (Nov. 2014) ("TX FIP TSD").

[20] *Id.* at A-15 – A-26.

[21] *Id.* at A-49.

single source model, as it did in Arkansas. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,050; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,635.

EPA proceeded to complete the required four-factor reasonable progress analysis in those other states only after narrowing the list of potential point sources. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872. *See also* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,138, 9,352-53 (Feb. 18, 2014); Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,058-59 (Apr. 20, 2012); and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,624-26 (Sept. 21, 2011). No doubt, this process was utilized because the Regional Haze Rule requires that additional controls for proposed emission reductions, as identified in an implementation plan, *must be needed to achieve reasonable progress*.[22] EPA's failure to follow these same procedures in the Arkansas Proposed FIP is completely inconsistent with its prior actions and renders the Proposed FIP arbitrary and capricious.

(ii) EPA's review and determination of cost effectiveness is inconsistent with other state programs.

EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After making the unsubstantiated and unsupportable determination to target only Independence, EPA applied different dollar per ton cost effectiveness thresholds for proposed controls at the plant, which are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's Proposal attempts to justify a cost effectiveness of dry FGD at Independence totaling \$2,477/SO_2 ton removed for Unit 1 and \$2,686/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,944. This far exceeds the cost threshold approved by EPA for reasonable progress controls for other states. *See* Section III.C.3 below.

(iii) EPA's evaluation and application of NOx control requirements is inconsistent with other state programs.

EPA's decision to evaluate *and propose* NOx controls at Independence stands completely opposite its decision not to even evaluate NOx controls for Texas' point sources despite similar visibility conditions. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions."). EPA's decision in this Proposal to impose NOx limits on Independence is inexplicable given the very low visibility improvement projected and the fact that such limits are completely unnecessary for Arkansas to stay below the URP. *See* 40 C.F.R. §§ 51.308(d)(1)(ii) and (d)(3) (explaining that "emission reduction measures" must be necessary to achieve reasonable progress goals). Visibility at Arkansas' Class I areas is only insignificantly impacted by all Arkansas point sources, even less so by point source contributions of NOx, and almost not

[22] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and (d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

at all by Independence. *See* Section III.C.2 below. Further, Arkansas has sufficiently documented that those same Class I areas remain well ahead of the approved URP. *See* Section III.C.1 below.

2. EPA is obliged to act consistently in promulgating rules.

Reviewed individually, the issues identified above evidence an unjustified and inconsistent application of the Regional Haze Rule. Collectively, they demonstrate EPA's complete disregard for consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). They further oblige the Agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a).

In EPA's Arkansas FIP Proposal, EPA abandoned the standardized criteria, procedures and policies that had been used in other regional haze SIPs/FIPs. Even more remarkable, EPA's failure to complete a necessary reasonable progress analysis is the same justification EPA used to reject Arkansas' SIP proposal in the first instance. *See* 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas regional haze SIP was based, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

C. Installing Scrubbers At Independence Is Not Necessary To Demonstrate Reasonable Progress And Cannot Be Justified At This Time.

Units 1 and 2 at the Independence Station are not subject to BART. 80 Fed. Reg. at 18,991. EPA nonetheless treats the units as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are "cost effective." EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). Only if further action is *necessary* for reasonable progress may EPA require additional controls and, even then, EPA must evaluate which controls are appropriate based on the statutory factors. *See* 42 U.S.C. § 7491(g)(1). EPA failed to do this here.

Arkansas' Class I areas, even without the proposed BART controls, are significantly below the URP and are on track to remain so for the next several years. Nonetheless, EPA has proposed to require emissions limits at Independence Units 1 and 2 based on the installation of SO_2 and NOx controls, ostensibly to achieve reasonable progress, and has offered two options for comment. Under Option 1, each coal-fired unit at Independence would be required to meet a rolling 30-day average SO_2 emission limit of 0.06 lb/MMBtu based on the installation and operation of dry FGD systems, and a rolling 30-day average NOx emission limit of 0.15 lb/MMBtu based on the installation and operation of LNB/SOFA. *Id.* at 18,994, 18,997. Under Option 2, the Independence coal-fired units would be required to meet only the SO_2 limit. *Id.* at 18,994.

EPA's justification for imposing SO_2 and NOx emission limits on Independence is not based on rational policy, legal or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NOx point source emissions." *Id.* at 18,992. EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. *Id.* at 18,994-97. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NOx emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress purposes. EPA has not used such an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis in any other Regional Haze FIP. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPS. *See* Section III.B above. Further, emission limits on Independence during at least the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period.

EPA also improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, has significantly over-estimated Independence's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at Independence.[23] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols - biogenic ("SOAB"), mobile sources, and Arkansas area sources,[24] not by Arkansas point sources such as power plants. EPA's singular focus on Independence will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal, but will cost EAI's customers and co-owners over $1 billion.

1. Controls on Independence do not further the goal of the Regional Haze Program.

The goal of the Regional Haze Program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I areas resulting from manmade air pollution. 42 U.S.C. § 7491(a)(1). Notably, the goal is not simply to reduce

[23] It is noteworthy that EPA issued, on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[24] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, *Introduction to Area Source Emission Inventory Development*, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id.*

emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2). The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The program is not designed to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

64 Fed. Reg. 35,714, 35,752 (July 1, 1999). EPA takes this extended period of time into account in providing guidance to the states on establishing their RPGs: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4; *see also id.* at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

Thus, the threshold question is whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal") (emphasis added). Here, where Arkansas is already below the URP for this planning period and projected to remain so for more than a decade, the answer is clearly no. EPA's proposed imposition of unnecessary controls is clearly unreasonable. *See Michigan v. EPA*, 135 S.Ct. at 2706 (requiring EPA's regulatory requirements to be "within the scope of its lawful authority" and its decision-making process to be "logical and rational").

(i) Arkansas' Class I areas are, and will remain, below the glide path well beyond the first planning period.

The proposed emission limits for Independence are not necessary to achieve reasonable progress because ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, *State Implementation Plan Review for the Five-Year Regional Haze Progress Report*, at 55-56 (May 2015) ("Arkansas Five-Year Progress Report").[25] Specifically, Caney Creek and Upper Buffalo have both shown improved visibility for the most impaired and least impaired days since 2001 and are projected to continue to improve. The current five-year average shows that, as of 2011, Caney Creek has achieved 73%

[25] Available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_reviewfinal-6-2-2015.pdf.

of Arkansas' 2018 RPG of 3.88 dv and Upper Buffalo has achieved 66% of Arkansas' 2018 RPG of 3.75 dv. Arkansas Five-Year Progress Report at 60. Based on the five-year rolling averages and projected data, both Class I areas are on schedule to achieve their 2018 RPGs for the 20% worst days. *Id.* at 55, 57. Data from Caney Creek and Upper Buffalo show that the goal of no visibility degradation on the 20% best days will be achieved and that visibility has and will continue to improve. *Id.* at 42-43. EPA acknowledges these facts in the Proposal: "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period." 80 Fed. Reg. at 18,992. As a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.[26]

Entergy has conducted additional modeling using the Comprehensive Air Quality Model with Extensions ("CAMx") and statistical analysis that supports this conclusion. The CAMx modeling demonstrates that the haze index at Caney Creek and Upper Buffalo will remain below the URP for many years to come.[27] Recent IMPROVE monitoring data show that the haze index has been consistently below the URP in both Caney Creek and Upper Buffalo. Trinity Consultants, Inc. ("Trinity") also performed statistical analyses on the data from both Caney Creek and Upper Buffalo to statistically project the haze index trend through 2018.[28] Using a Ranked Statistical Analysis, the haze index for the average of the W20 days in 2018 is projected to be 20.07 dv at Caney Creek and 20.91 dv at Upper Buffalo.[29] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path. *See* Figures 1 and 2.

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[26] The 5-Year Progress Report for Missouri also demonstrates that Mingo and Hercules Glades are on track to meet the 2018 visibility goals and Missouri has determined that further reductions are not necessary. *Missouri Regional Haze Plan: 5-Year Progress Report*, at 4, 17 (Aug. 29, 2014) ("The [monitoring] analyses in the 2009 RH plan demonstrate that the 2018 visibility goals for Mingo and Hercules Glades will be largely achieved from Electric Generating Unit (EGU) emission reductions resulting from the federal Clean Air Interstate Rule (CAIR) program."); *see also* Proposed Missouri SIP, 77 Fed. Reg. 11,958, 11,966 (Feb. 28, 2012) ("EPA proposes to find that Missouri has appropriately established goals that provide for reasonable progress towards achieving natural visibility conditions."); Final Missouri SIP, 77 Fed. Reg. 38,007 (June 26, 2012).

[27] The CAMx modeling was conducted by Trinity Consultants, Inc. Trinity's *Regional Haze Modeling Assessment Report*, which describes the CAMx modeling methodology that Trinity used to evaluate the visibility improvement of controls at Independence and White Bluff, is provided as Exhibit C to these comments.

[28] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

[29] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.

Figure 1

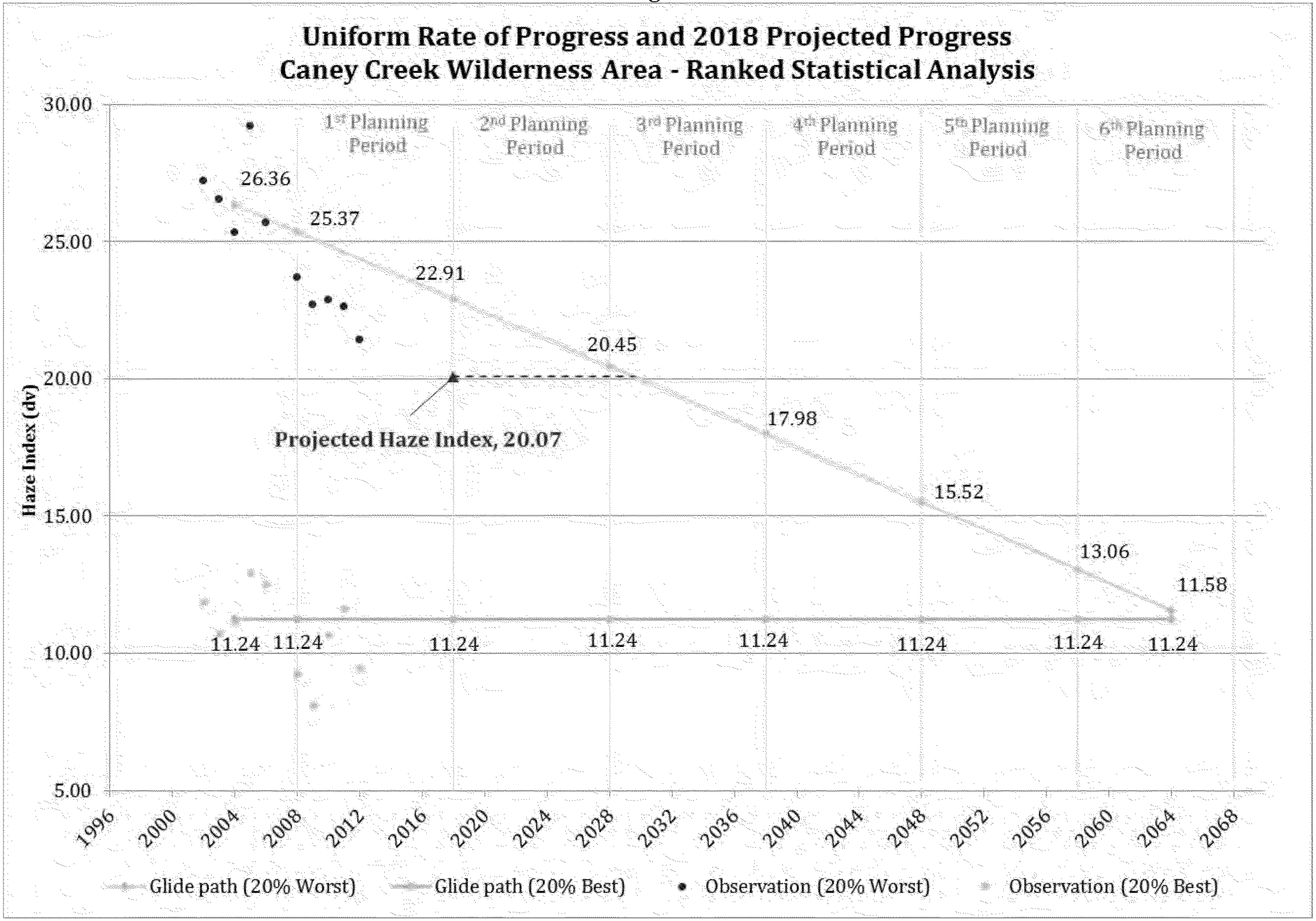
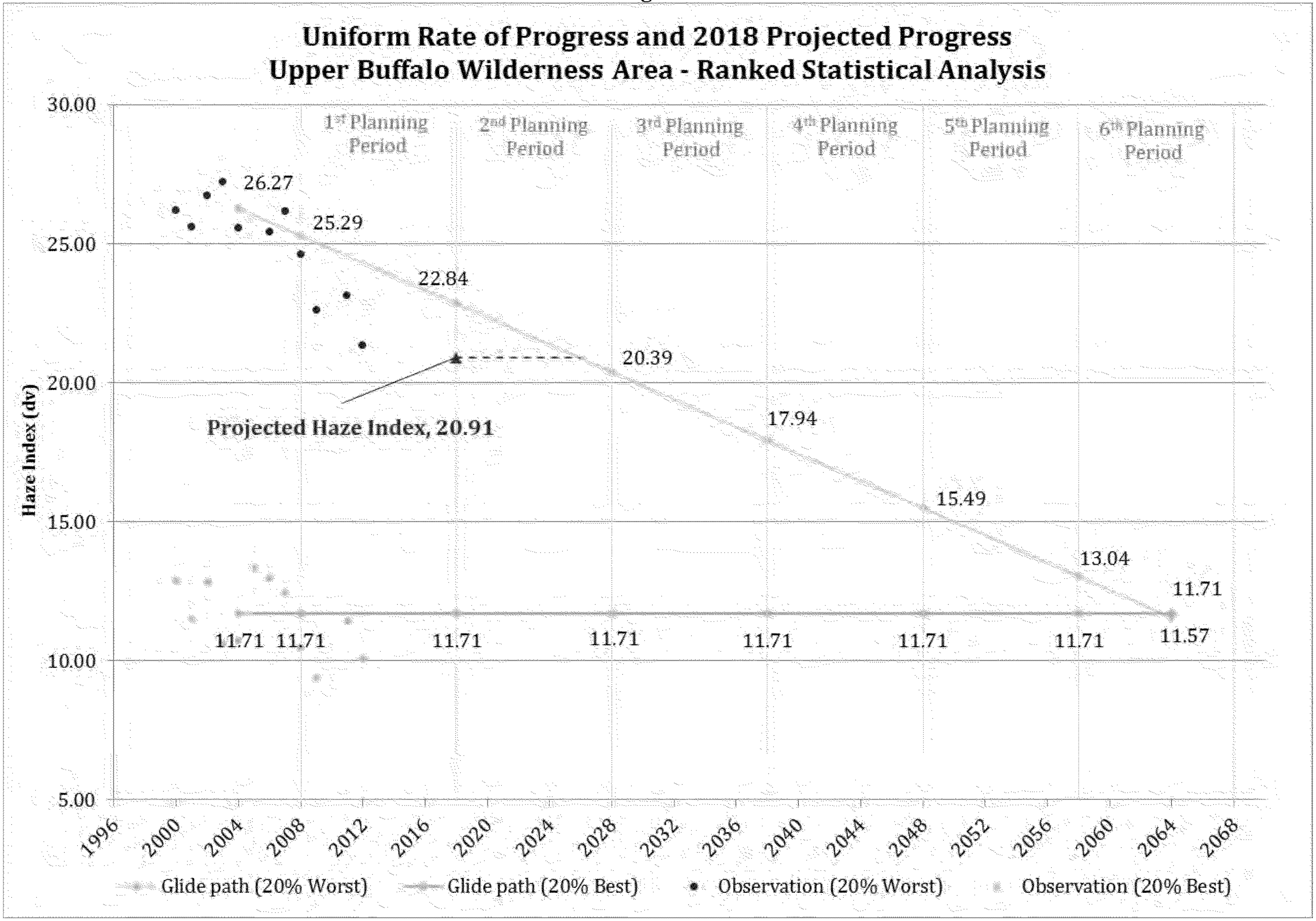

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
11.24
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 2


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
Projected Haze Index, 20.91
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figures 1 and 2 show the data plots for the 20% worst days and the 20% best days from the IMPROVE network for Caney Creek and Upper Buffalo, respectively. These plots demonstrate that the W20 days since 2007 have consistently been below the URP and that visibility is improving faster than the URP. Trinity applied a Ranked Statistical Analysis to all of the haze index values calculated using the new IMPROVE equation and the data from the IMPROVE monitoring network and constructed a future projection curve to statistically project the haze index at Caney Creek and Upper Buffalo in 2018. Trinity Report at Section 3.2. As demonstrated in Figure 1, the Ranked Statistical Analysis indicates that the haze index in 2018 at Caney Creek will be 20.07 dv, which is 2.84 dv below the URP. Indeed, if EPA does nothing at all (i.e., imposes no BART limits on sources in Arkansas or emission limits on Independence), Caney Creek would not approach the glide path until 2030. Figure 2 shows very similar results for Upper Buffalo, which would not approach the glide path until at least 2026. In light of these projections, which align with ADEQ's glide path demonstrations (*see* Arkansas Five-Year Progress Report at 57-60), SO_2 and NOx emission limits at Independence are unnecessary for reasonable progress purposes for at least a decade.

Notably, the Ranked Statistical Analysis conservatively assumes that there will be no additional emissions reductions resulting in visibility improvements after 2018, including emissions reductions from out-of-state sources, which cause over 50% of the visibility impairment in Arkansas Class I areas, or from area and mobile sources, which account for approximately 9.25% of the visibility impairment at Caney Creek and 9.68% at Upper Buffalo.[30] Assuming that MATS achieves the emissions reductions that EPA projects in terms of acid gas controls and retirements,[31] that CSAPR tightens the SO_2 emission budgets in the second phase, that sources will be forced to make additional SO_2 and NOx reductions to comply with the 1-hour SO_2 NAAQS and the revised ozone NAAQS, and that the Phase 2 CAFE fuel economy standards drive further reductions from mobile sources, the haze index in Caney Creek and Upper Buffalo will continue to improve beyond 2018 without controls on Independence.

(ii) Emissions from out-of-state sources and Arkansas mobile and area sources have a more significant impact on Arkansas' Class I areas.

In the Proposal, EPA's reasonable progress analysis primarily focuses on point source contributions to light extinction at Caney Creek and Upper Buffalo. As a result, EPA chose to limit its evaluation of potential reasonable progress controls solely to Arkansas' largest emitting point sources, and, specifically, to Independence. However, as demonstrated in Figures 3 and 4 below, Arkansas point sources are relatively insignificant contributors to visibility impairment in Caney Creek and Upper Buffalo compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.[32]

[30] These percentages are based on CENRAP's Particulate Matter Source Apportionment Technique ("PSAT") tool.
[31] Entergy expects the MATS Rule will go forward before the end of this planning period along with the associated emission reductions. *See* footnote 5 above.
[32] Figures 3 and 4, as well as Figures 5 and 6, were developed by extracting the modeled source apportionment extinction data from the CENRAP PSAT tool for Caney Creek and Upper Buffalo. The data obtained were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

Figure 3

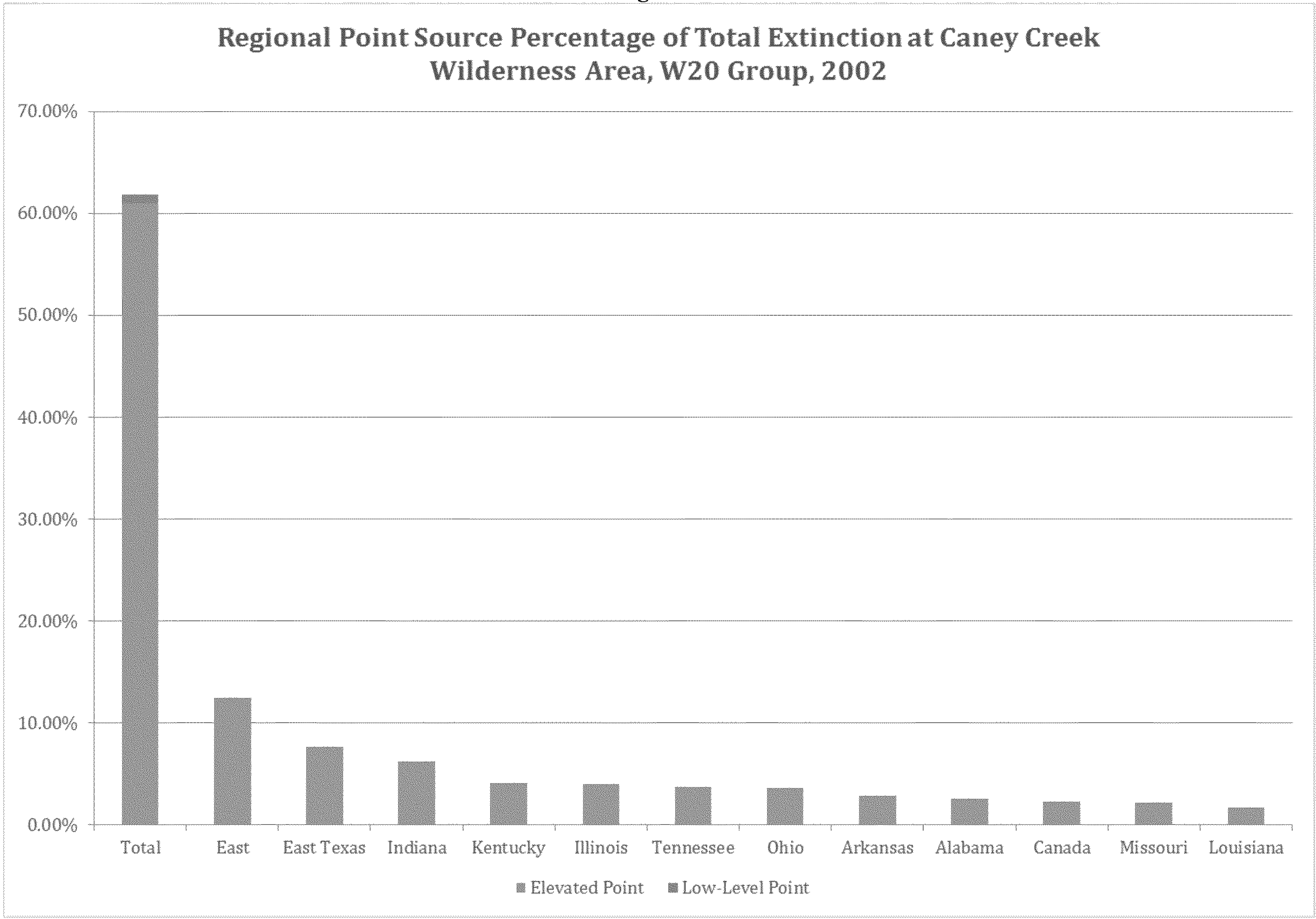
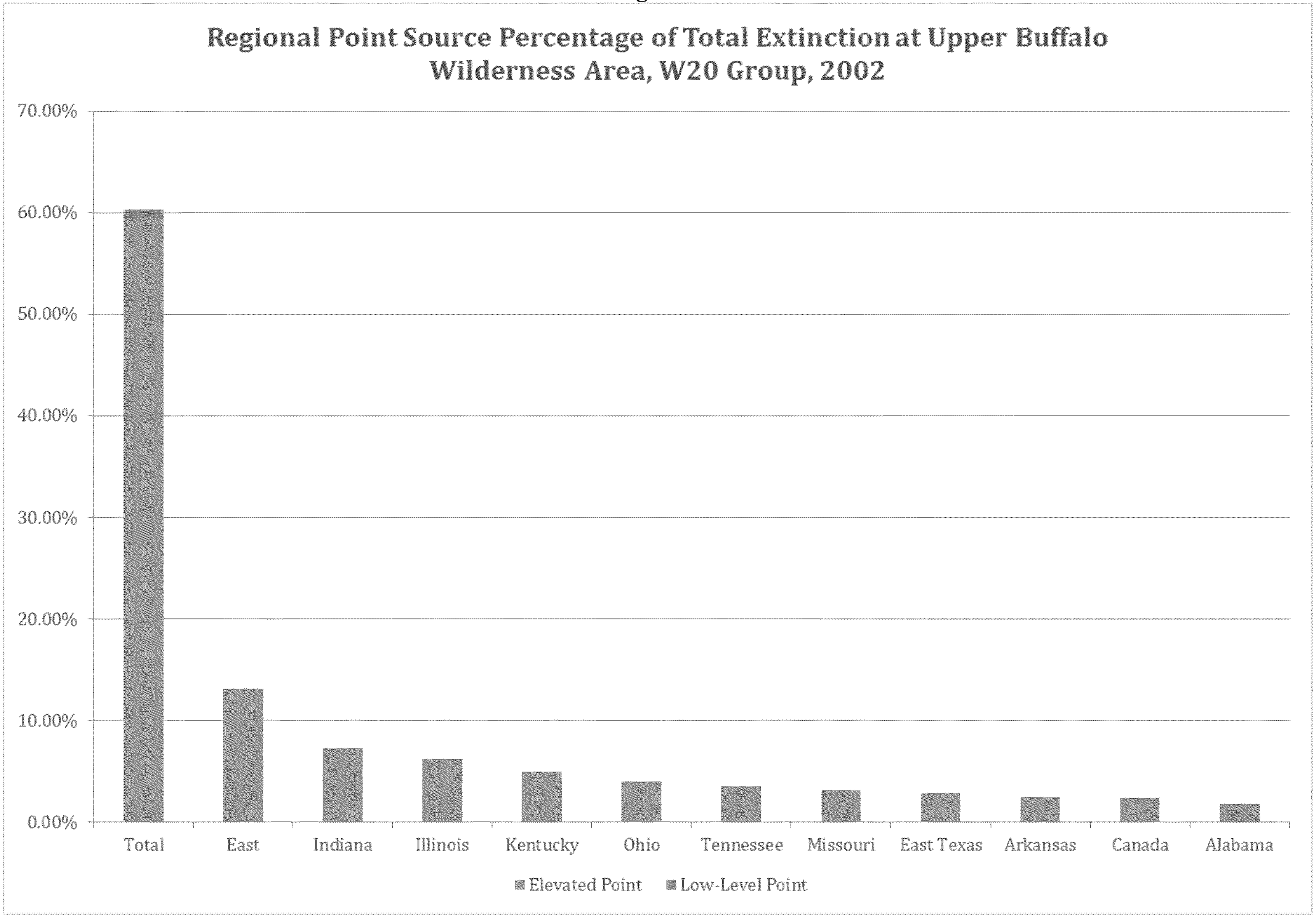

Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Elevated Point
Low-Level Point

Figure 4


Regional Point Source Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Elevated Point
Low-Level Point

Figures 3 and 4 display the modeled percent contribution of elevated and low-level point sources to the total light extinction from the significantly contributing geographic regions. Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. Of a total point source contribution of 61.85% at Caney Creek in 2002, Arkansas's point sources contributed only **2.87%**, making Arkansas the eighth highest point source contributor. Similarly, of the 60.35% total point source contribution at Upper Buffalo in 2002, Arkansas was the ninth highest point source contributor with only a **2.47%** contribution.

In addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 below.

Figure 5

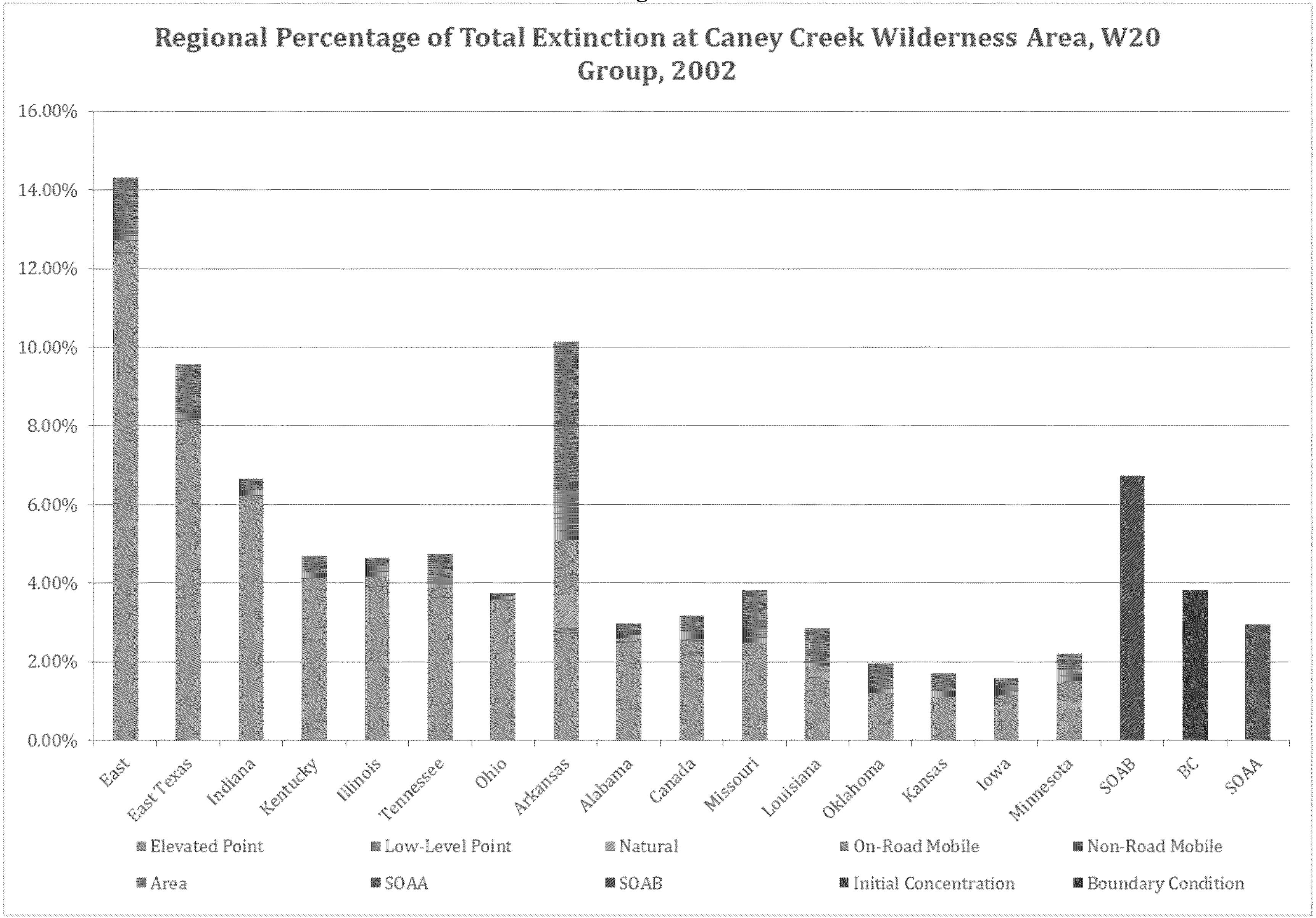
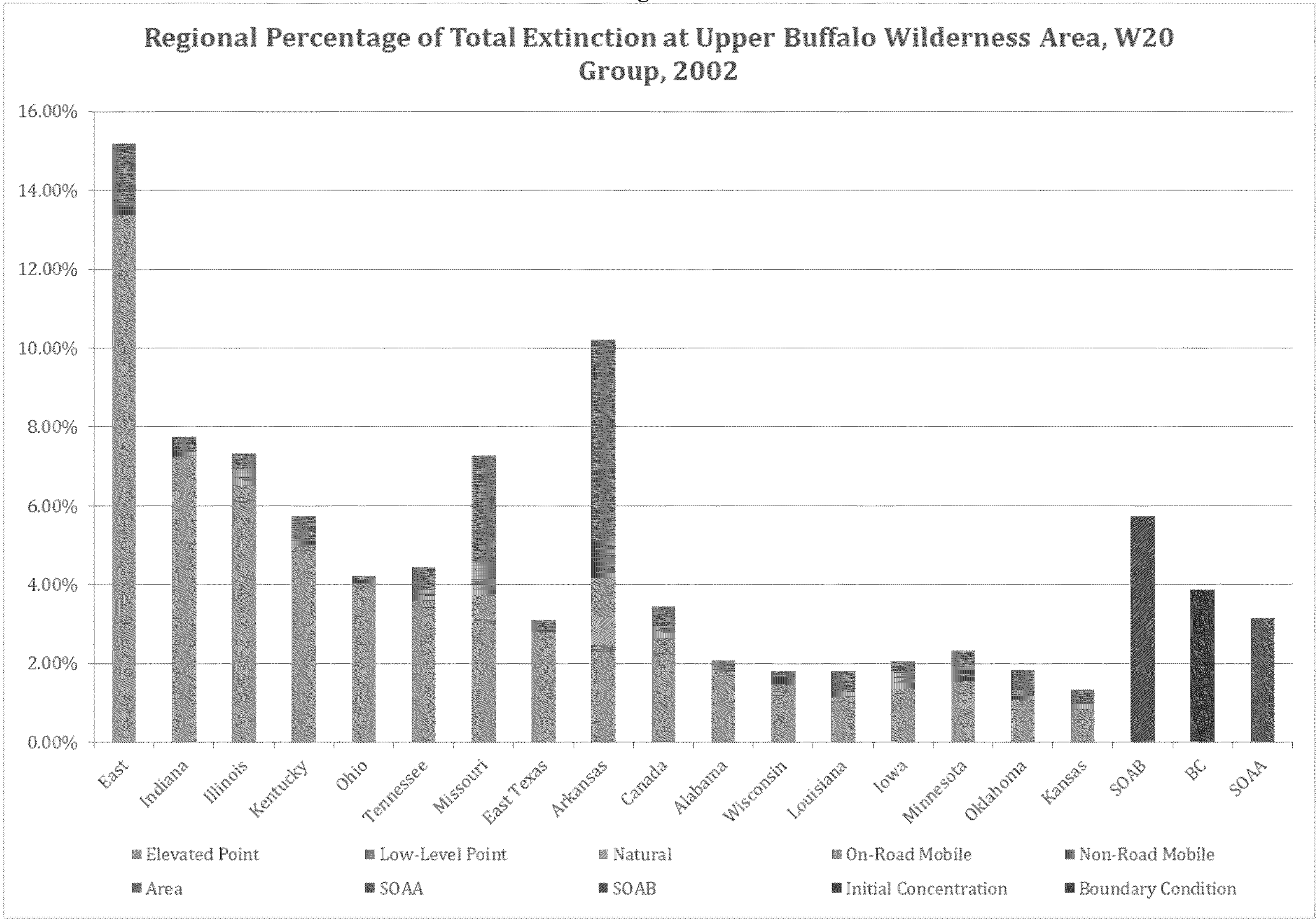

Regional Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Oklahoma
Kansas
Iowa
Minnesota
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

Figure 6


Regional Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Wisconsin
Louisiana
Iowa
Minnesota
Oklahoma
Kansas
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

At Caney Creek, Arkansas area sources contribute **3.75%** of the overall extinction while Arkansas' combined point source category (i.e., elevated and low-level point sources) contribute only **2.87%**. Even more significantly, Arkansas area sources contributed **5.09%** towards extinction at Upper Buffalo compared to **2.47%** from the combined Arkansas point sources.

Independence's emissions, which comprise only a portion of Arkansas' point source emissions, have even less of an effect on light extinction in either Class I area. As a result, installing emissions controls on Independence will not meaningfully change the haze index at either Class I area.

(iii) Emissions from out-of-state sources will continue to improve.

Entergy's analysis demonstrates that Arkansas' Class I areas will remain below the glide path in the first planning period and well into the second based on actual data (*see* Section III.C.1.i above); however, the analysis also demonstrates that, due to continued emissions reductions at sources outside of Arkansas, these reductions will continue, furthering Arkansas' progress towards background visibility, without controls on Independence. Point source emissions from the other states included in CENRAP's modeling have been steadily decreasing since the early 2000's and that trend is expected to continue. Indeed, a number of sources in East Coast states have recently announced retirements. The U.S. Energy Information Administration predicts that 60 gigawatts of coal-fired power plant capacity will retire by 2020.[33] These units are significant contributors to visibility impairment at Caney Creek and Upper Buffalo and their retirement will further improve visibility. The second phase of CSAPR, the 1-hour SO_2 NAAQS and the revised ozone NAAQS also will result in significant reductions in SO_2 and NOx emissions from the largest point source contributors to Caney Creek and Upper Buffalo, which are all located outside of Arkansas. *See* Figures 7 and 8 (demonstrating declining emissions trends and the contributions of EGUs).

[33] http://www.eia.gov/todayinenergy/detail.cfm?id=15031#

Figure 7

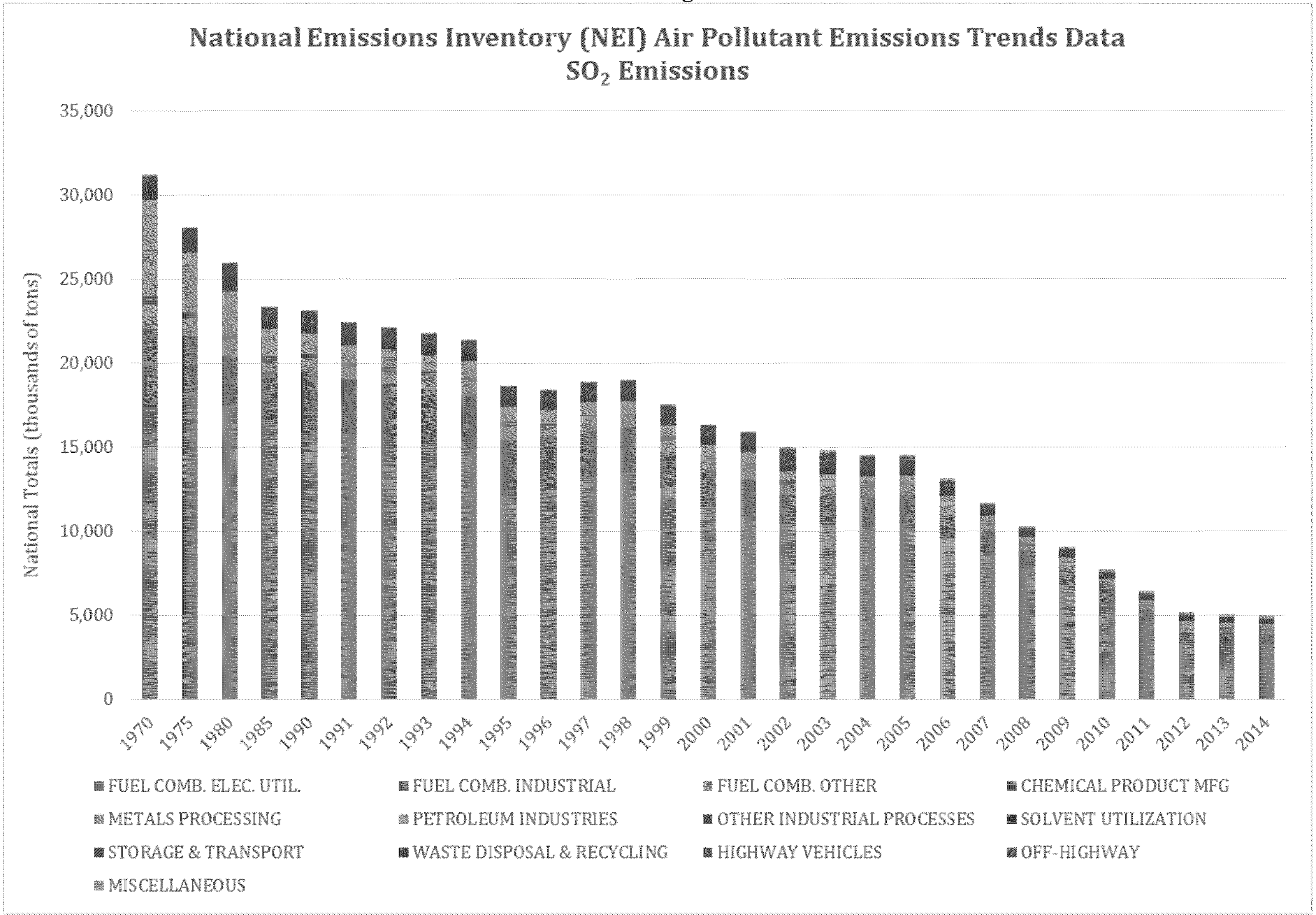
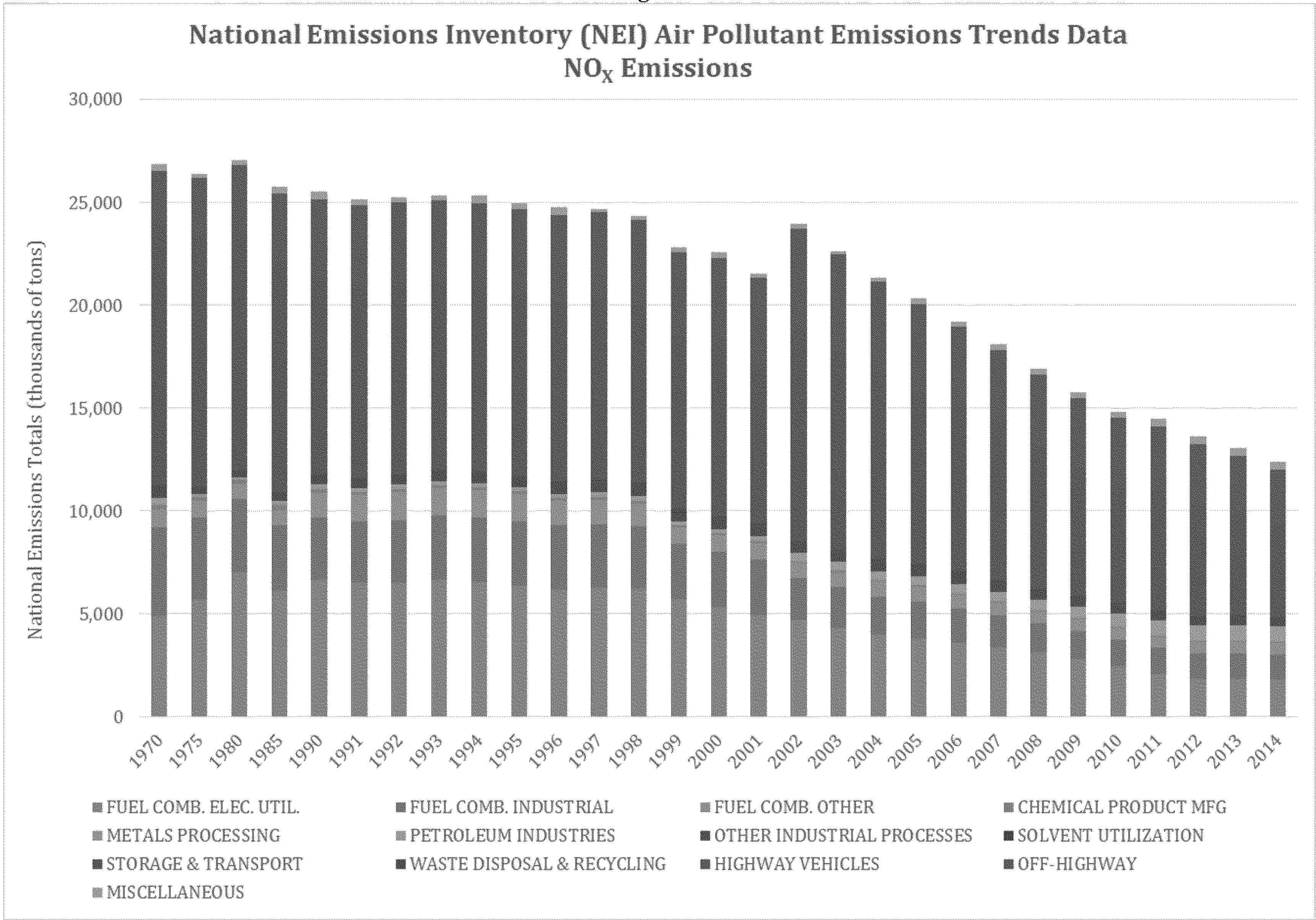

National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
SO_2 Emissions
National Totals (thousands of tons)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

Figure 8


National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
NO_X Emissions
National Emissions Totals (thousands of tons)
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

According to EPA's Reasonable Progress Guidance, the Agency should have taken the emissions reductions anticipated from CSAPR, as well as other Clean Air Act programs, into account in setting the proposed RPGs for Arkansas:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

Reasonable Progress Guidance at 4-1. EPA completely failed to undertake this "important step" in proposing the RPGs for Arkansas and instead simply focused on controls at Independence.

2. Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis benefit toward reasonable progress.

EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo. 80 Fed. Reg. at 18,990. However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. *Id.* The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. *Id.* The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018. *See* Figures 9 and 10.[34] This reflects only one half of one percent of the visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO_2 and NOx controls at Independence are warranted.

[34] Figures 9 and 10 assume no FIP controls on any of the Arkansas sources. Also, the total haze index values presented in Figures 9 and 10 are based on Entergy's CAMx model predicted total contribution calculated using the new IMPROVE equation, whereas the projected haze index values in Figures 1, 2, and 11 - 14 are based on Trinity's Ranked Statistical Analysis and represent the average haze index for the W20 days. *See* Section III.C.1.i, above.

Figure 9

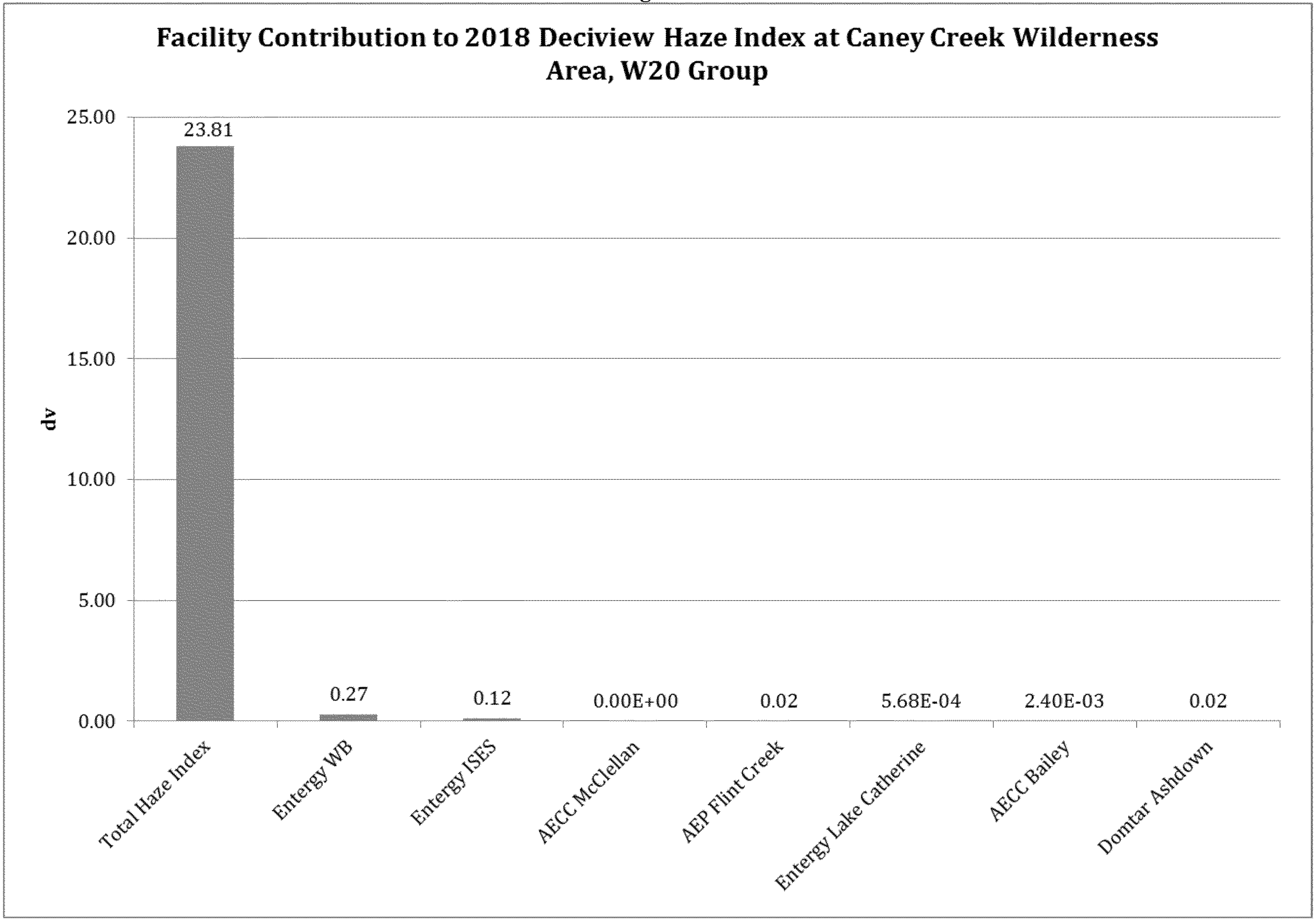
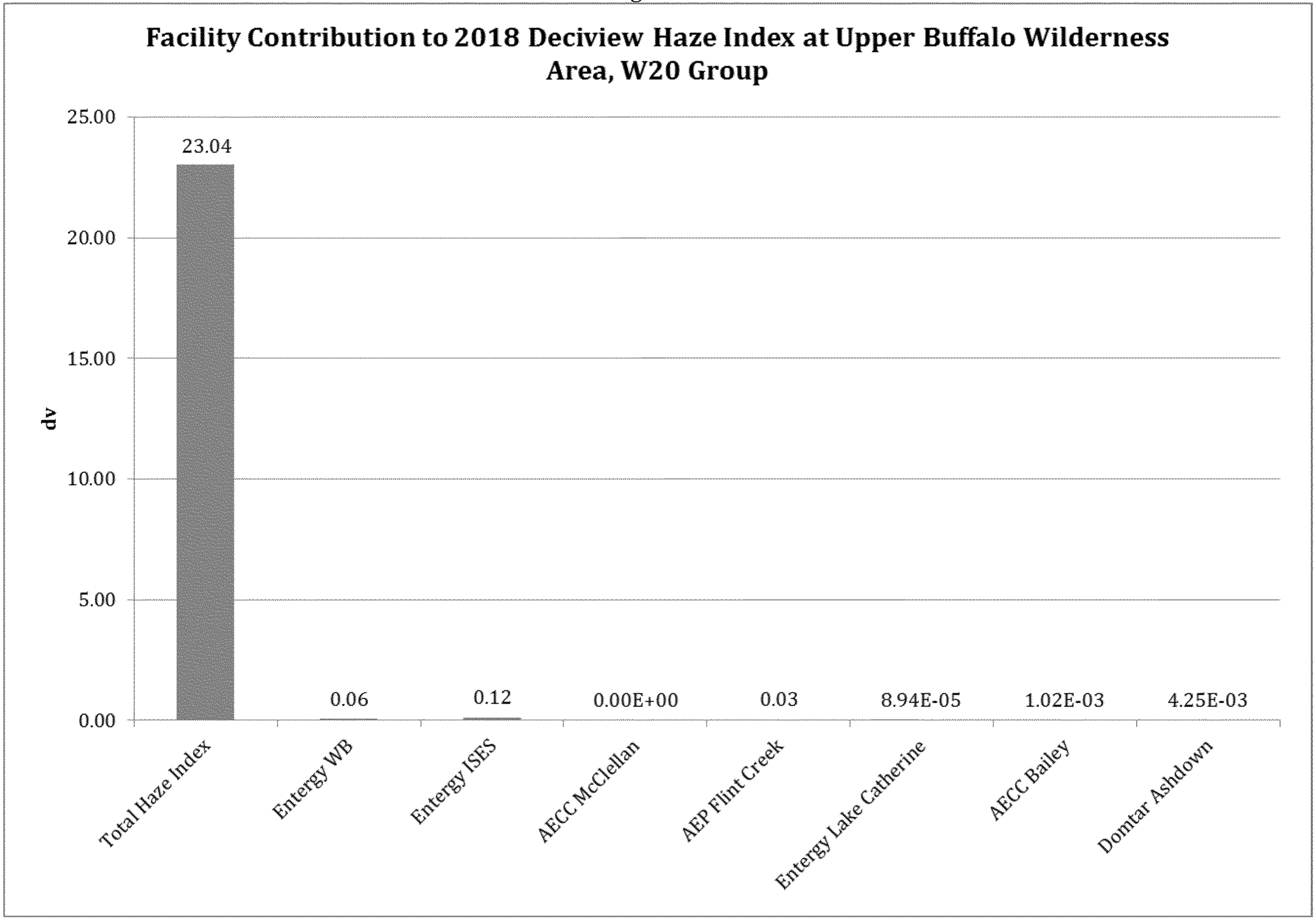

Facility Contribution to 2018 Deciview Haze Index at Caney Creek Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.81
0.27
0.12
0.00E+00
0.02
5.68E-04
2.40E-03
0.02
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

Figure 10


Facility Contribution to 2018 Deciview Haze Index at Upper Buffalo Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.04
0.06
0.12
0.00E+00
0.03
8.94E-05
1.02E-03
4.25E-03
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

(i) CALPUFF modeling cannot be used to justify reasonable progress controls at Independence.

Entergy acknowledges that, under the Regional Haze Rule, "the URP does not establish a 'safe harbor' for the state in setting its reasonable progress goals." 80 Fed. Reg. at 18,992 (referencing 64 Fed. Reg. at 35,732). Nonetheless, EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be "reasonable based upon the statutory factors." *Id.* EPA has explained that this requires a consideration of the projected visibility benefit expected from the controls. *Id.* at 18,993.

EPA admits that it did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail" approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels. 80 Fed. Reg. at 18,997-98. EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question than a proper reasonable progress analysis. TX FIP TSD at A-35. As EPA itself has recognized, CALPUFF is overly simplistic and greatly overstates the effect of single source emissions. BART Guidelines, 70 Fed. Reg. 39,104, 39,121 (July 6, 2005) ("there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source."). CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx.

EPA has recognized that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78. BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days. *Id.* at 74,878.

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014) ("Draft Modeling Guidance") discusses the use of photochemical grid models and notes that Community Multiscale Air Quality Model ("CMAQ") and CAMx are the most commonly used models for attainment demonstrations. The Draft Modeling Guidance specifically notes that "a modeling based demonstration of the impacts of an emissions control scenario... as part of a regional haze assessment usually necessitates the application of a chemical transport grid model." Draft Modeling Guidance at 22.[35] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

According to the Draft Guidance, "the emission sources included in the analysis must be comprehensive, including emissions from all source categories" (i.e., point sources, non-point stationary sources, on-road and non-road mobile sources, fires, and biogenic sources) and "'all' sources of emissions." *Id.* at 32, 36. A CAMx modeling analysis includes a comprehensive inventory, capturing each of these source categories, which are then available to react with available precursors. By using the comprehensive inventory, this limits the amount of precursors available to react with the emissions from a facility or source in question. This has been referred to by EPA as a "dirty background analysis." CALPUFF analyses conducted in support of BART determinations do not consider the full inventory of sources and thus do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze impacts in a modeled simulation using CALPUFF. This is referred to by EPA as a "clean background analysis." Therefore, the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

Notably, EPA recently issued a proposal on July 29, 2015, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* ("Guideline"), in Appendix W to 40 C.F.R. Part 51. Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. Instead, EPA's proposal emphasizes the use of chemical transport models for assessing visibility impacts from a single source or small group of sources. According to the Agency,

> Chemical transport models are well suited for the purpose of estimating long-range impacts of secondary pollutants, such as $PM_{2.5}$, that contribute to regional haze and other secondary pollutants, such as ozone, that contribute to negative impacts on vegetation through deposition processes. These multiple needs require a full chemistry photochemical model capable of representing both gas, particle, and aqueous phase chemistry for $PM_{2.5}$, haze, and ozone.

80 Fed. Reg. at 45,349. CALPUFF is clearly inferior in this regard.

Indeed, EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values*,[36] which EPA has made available as a supporting document for the proposed revisions to Appendix W, makes clear that CALPUFF should not be used for a reasonable progress analysis. The report explains that, "[a] modeling system that treats emissions from all known anthropogenic and biogenic emissions sources with

[35] The Draft Modeling Guidance is available at http://www.epa.gov/scram001/guidance/guide/Draft_O3PM-RH_Modeling_Guidance-2014.pdf.
[36] Docket ID EPA-HQ-OAR-2015-0310-0004.

realistic chemical and physical transformations should be utilized to estimate future visibility conditions at a Class I area. The most appropriate tool that contains these qualities is a photochemical grid model [such as CAMx]." *Id.* at 6. It further explains that "the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal.... Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources." *Id.* at 9.

(ii) The CALPUFF modeling vastly overstates the potential visibility improvement from controls on Independence.

EPA's CALPUFF modeling indicates that the SO_2 and NOx emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. *See* Summary of Additional Modeling for Entergy Independence, at 8, Table 5 (Apr. 2015), EPA Docket ID EPA-R06-OAR-2015-0189-0147. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling. 80 Fed. Reg. at 18,990. This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.83 - 0.86 dv of impairment (23-24 dv x 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. *Id.* at 18,990. Independence's SO_2 and NOx emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NOx limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

Another illustration demonstrates why CALPUFF greatly overstates the benefits of overall visibility benefits from proposed emission limits. In the Proposal, EPA projects the visibility benefits from the proposed BART controls based on CALPUFF modeling. Based on CALPUFF, EPA's proposed BART limits at White Bluff, Flint Creek Power Plant, Carl E. Bailey Generating Station, John L. McClellan Generating Station, Lake Catherine and Domtar Ashdown Power Boilers will result in projected combined visibility benefits of approximately 4.3 dv at Caney Creek.[37] *See* Figure 11 below. Based on a statistical projection of the haze index in Caney Creek (*see* Section III.C.1 above), that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP

[37] Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling.

would not reach that haze level until approximately 2048.[38] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.

[38] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038 - the end of the third planning period. *See* Figure 12.

Figure 11

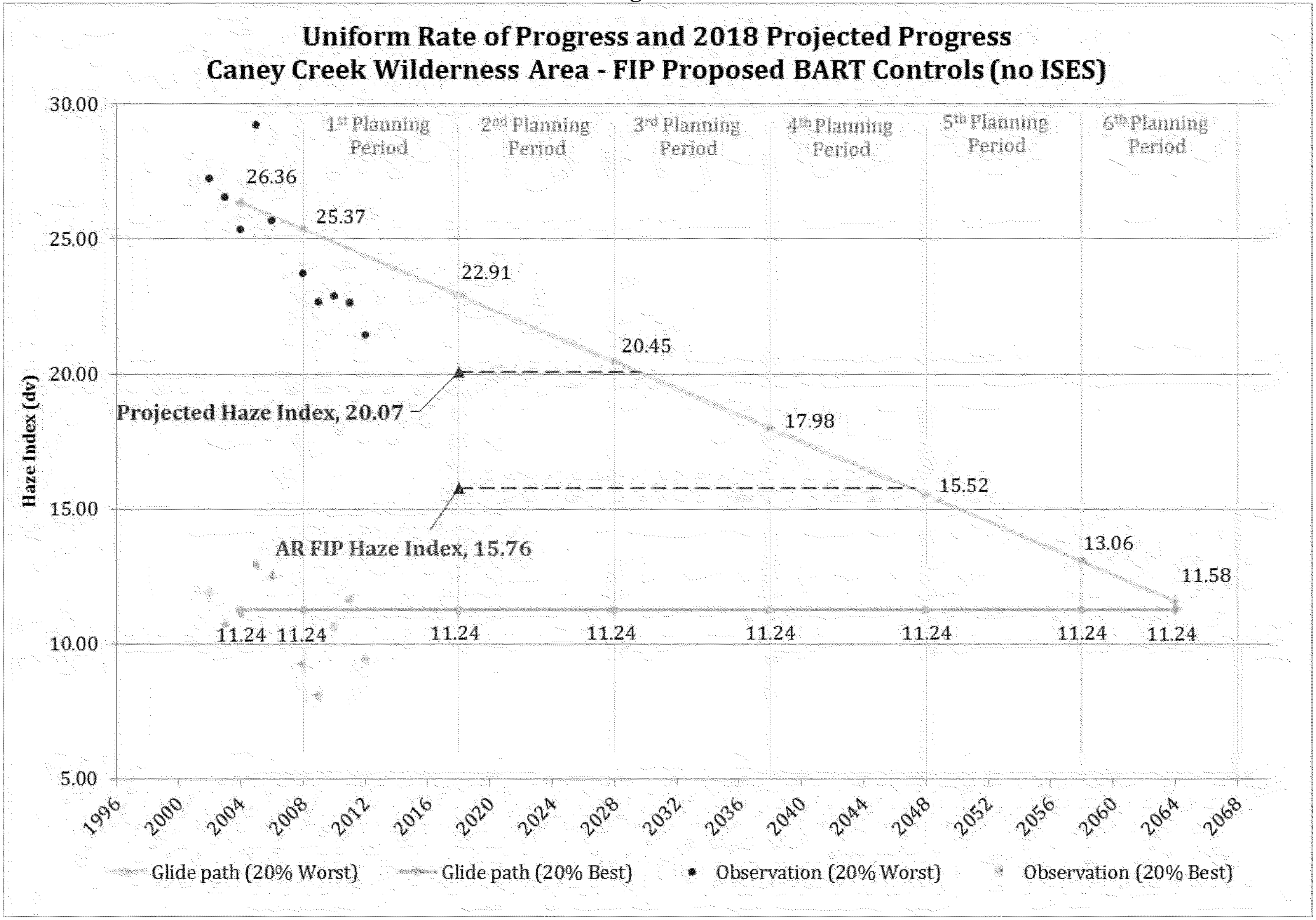
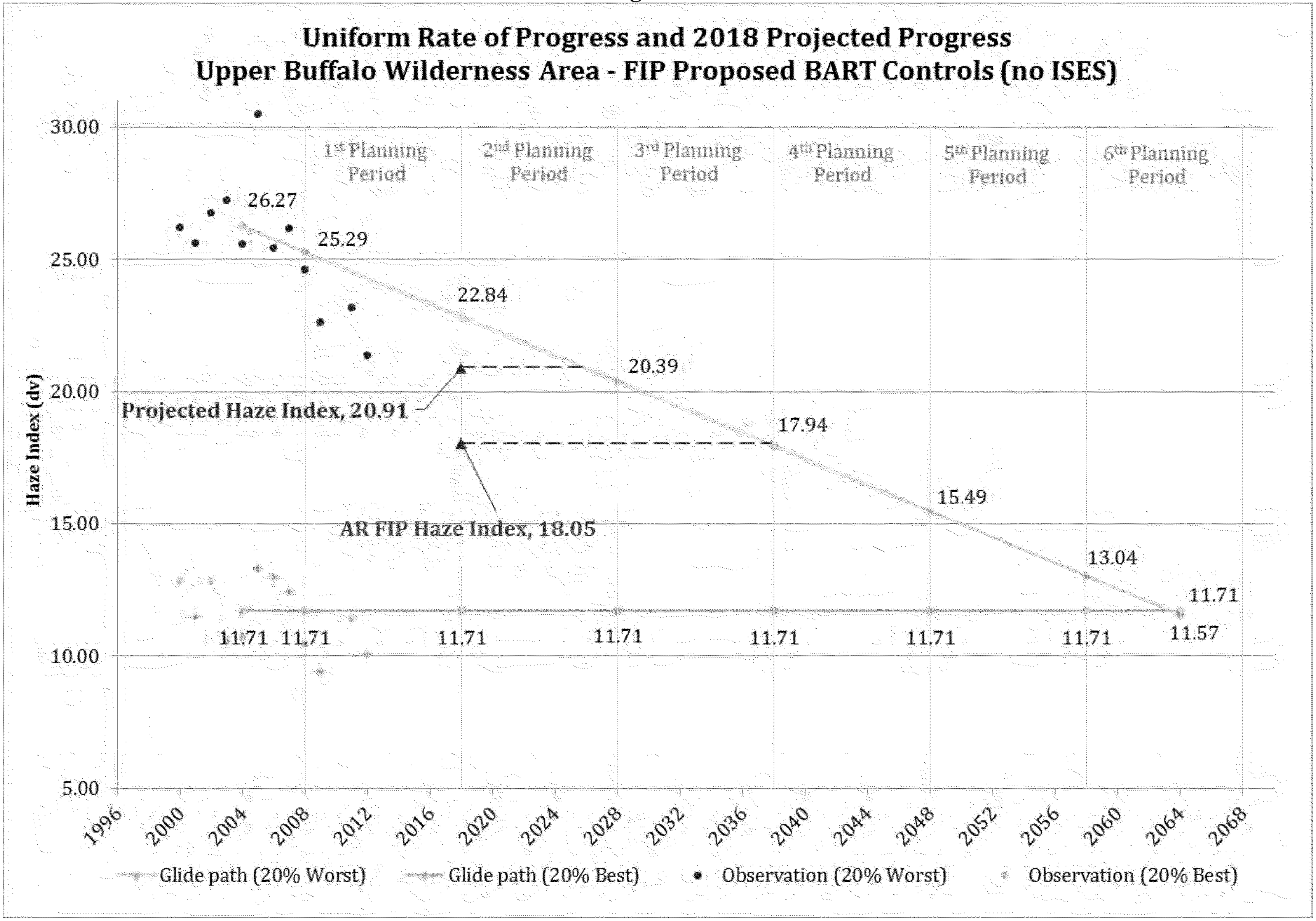

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
AR FIP Haze Index, 15.76
11.24
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 12


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
Projected Haze Index, 20.91
AR FIP Haze Index, 18.05
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

If EPA insists on relying on CALPUFF to evaluate the projected visibility benefits of requiring controls on Independence, it must be consistent and use CALPUFF to evaluate the need for such controls for purposes of demonstrating reasonable progress. As demonstrated in Figures 11 and 12, controls at Independence cannot be justified for reasonable progress based on the CALPUFF results, which predict an improvement of several deciviews solely from BART controls.

(iii) Controls on Independence will not yield perceptible visibility benefits.

As demonstrated above, EPA's CALPUFF modeling greatly overstates the visibility benefits that would result from installing controls at Independence and should be disregarded. Further, when EPA used the CENRAP model (an appropriate multi-source model) to assess overall visibility impairment, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP – all BART controls plus controls at Independence – would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. 80 Fed. Reg. at 18,998, Table 67. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NOx emissions in Arkansas, *see id.* at 18,991, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately **0.08** dv at Caney Creek and **0.07** dv at Upper Buffalo).[39] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

Not only does this demonstrate the illogic of relying on CALPUFF for reasonable progress, it demonstrates that the realistic benefits resulting from installing controls at Independence will be inconsequential and will contribute virtually nothing to visibility improvement at either Class I area. According to EPA, one deciview reflects "perceptible changes" in visibility. *See* Proposed Regional Haze Rule, 62 Fed. Reg. 41,138, 41,145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."). Thus, the measure of visibility improvement is based on *noticeable changes*. By EPA's own standard, a total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources would not be perceptible to the human eye. Likewise, a total deciview improvement at Upper Buffalo of 0.19 dv would not be discernable. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF.[40] Requiring imperceptible visibility improvements is simply unreasonable. The

[39] These values are the calculated improvement based on EPA's "scaling methodology." *See* 80 Fed. Reg. at 18,997.
[40] Even if the CALPUFF results were accurate, it is highly unlikely that such improvements would be perceptible. Studies have demonstrated that not only is the deciview scale not uniform in perception over a wide range of visibility conditions, but a 1-deciview change in visibility is not even perceptible to the human eye. *See* Exhibit E, *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Manage. Assoc. (2002). Instead, according to the Study, deciview improvements likely would need to be in the range of 2 to 5 dv to be perceptible. *Id.* at 1242, Figure 2.

CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013).

In addition, the demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. *See Chemical Characteristics of Inorganic Ammonium Salts in $PM_{2.5}$ in the Atmosphere of Beijing (China)*, A. Ianniello, F. Spataro, G. Esposito, I. Allegrini, M. Hu, and T. Zhu, 11 Atmos. Chem. Phys., at 10804 (2011).[41] For example, due to a high chemical affinity, an ammonia molecule reacts with SO_2 molecules to form sulfate before reacting with NOx molecules to form nitrate. If abundant SO_2 is present in the atmosphere, any increase in NOx emissions will not result in a linear increase in nitrate formation. As a result, there may not be any increase in the predicted regional haze. On the contrary, if abundant NOx molecules are present, then any reduction in SO_2 molecules will not result in a significant reduction in haze as NOx will substitute the reduced SO_2 in the reaction. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. *See* 40 C.F.R. § 51.301 (definition of "deciview"). As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

(iv) EPA has offered no justification for requiring controls to achieve reasonable progress for this planning period when the controls cannot even be installed until the next planning period.

EPA further exceeds its authority by proposing to require controls in the name of achieving reasonable progress during the first planning period even though the emissions reductions the Agency proposes would not be achieved until well into the second planning period. The Proposed FIP covers a planning period of 2008-2018. The major SO_2 emissions control technology that would have to be installed at Independence to meet the proposed SO_2 emission rate limitation cannot be designed, constructed and operational in less than five years.[42] Given the likely effective date of the FIP in 2016, SO_2 controls at Independence could not be installed and operational before sometime in 2021.[43]

Adopting a reasonable progress goal for the first planning period based on the installation of controls that will not be completed until well after the deadline to achieve that reasonable progress goal makes no sense, and EPA has completely failed to explain why it is appropriate. Indeed, EPA will have multiple bites at this apple – there are still four more planning periods

[41] Available at http://www.atmos-chem-phys.net/11/10803/2011/acp-11-10803-2011.pdf.

[42] EPA recognizes this timeframe is necessary for the installation of SO_2 controls at Independence by proposing that Independence meet the SO_2 emissions limits no later than five years after the effective date of the final rule. 80 Fed. Reg. at 18,994. Entergy agrees with EPA's conclusion that a five-year timeframe would be necessary for the installation of controls at Independence.

[43] The Proposed FIP provides for NOx emission limitations to be met three years after the effective date of the FIP, which would not be earlier than sometime in 2019.

during which the necessity of reasonable progress controls can be evaluated. Controls on Independence should not be considered until these subsequent planning periods, and should not be imposed for a planning period that will have ended by the time any emissions reductions can be achieved at Independence. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4.

3. The proposed controls are not cost effective.

EPA's secondary justification for imposing controls on Independence is that it is, in EPA's opinion, cost effective to do so. 80 Fed. Reg. at 18,994-97. First, EPA's cost analysis for the proposed controls at Independence relies upon the control cost analysis for White Bluff, *see* SO_2 Cost TSD at 16, which is inappropriate. By simply relying on its White Bluff cost analysis without undertaking a site-specific analysis for Independence, EPA did not follow the steps necessary to identify the costs of controls for reasonable progress purposes. EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters. Reasonable Progress Guidance at 5-1.

Second, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, Entergy disagrees with EPA's estimated costs for the installation of dry scrubbers at White Bluff. *See* Section III.A.2 above. Assuming that dry FGD controls at Independence would cost the same as at White Bluff, the controls at Independence also would cost over $1 billion. *See* Section III.A.3 above. This is not cost effective on a $/ton basis for reasonable progress purposes as it would result in $4,234 per ton of SO_2 removed at Independence Unit 1 and $3,909 per ton of SO_2 removed at Independence Unit 2.

Finally, even if EPA's cost analysis as detailed in the SO_2 Cost TSD were correct, EPA's determination that the controls are cost effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

(i) Requiring over $1 billion in controls at Independence to achieve an unnecessary and imperceptible change in visibility at Arkansas' Class I areas is patently unreasonable.

Despite the flaws in EPA's analysis of Entergy's costs, EPA concludes that dry FGD is cost effective at $2,477 per ton of SO_2 removed for Independence Unit 1 and $2,286 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,994. Dry FGD is not cost effective for reasonable progress controls. These costs are higher than other cost per ton thresholds in RPG determinations in EPA-approved SIPs. The Kentucky Regional Haze SIP, 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011), used $2,000 per ton SO_2 as a screening threshold for cost effectiveness based on CAIR. In the North Carolina Regional Haze SIP, 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012), EPA approved the state's decision not to implement reasonable progress controls due to limited improvement in visibility even though cost effectiveness values were described as ranging "from 912 to 1,922 dollars per ton of SO_2 removed ($/ton SO_2), and the average costs per utility system ranged from $1,231 to $1,375/ton SO_2." EPA's estimated cost effectiveness of dry FGD at Independence is significantly higher than these thresholds, at $2,477/$SO_2$ ton removed for Unit 1 and \$2,286/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,994. Further, EPA has indicated that control costs found to be reasonable in the BART context may nonetheless be considered too costly in the reasonable progress context. *See* Final North Dakota SIP Approval/Disapproval, 77 Fed. Reg. 20,894, 20,936 (Apr. 6, 2012) (accepting North Dakota's determination that a level of \$2,593 per ton of SO_2 removed was not reasonable and too costly in the reasonable progress context even though it is within the range EPA "ha[s] considered reasonable in the BART context"). Despite these prior actions, EPA unreasonably concludes that the proposed controls at Independence are cost effective for reasonable progress purposes.

Additionally, EPA failed to consider the cost effectiveness of the controls relative to the visibility benefit that would result. EPA's own guidance notes that for "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." Reasonable Progress Guidance at 5-2. Here, EPA gave no consideration to the dollar-per-deciview resulting from installing scrubbers at Independence. If EPA had done so, it would recognize that the costs are approximately **\$1.33 billion** per dv improvement at Caney Creek and **\$1.53 billion** per dv improvement at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Where additional visibility improvement is not needed to remain below the glide path, such an exorbitant cost cannot be justified. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1149 (9th Cir. 2015) ("*NPCA*") (upholding EPA's decision not to require reasonable progress controls because of lack of cost-effectiveness, finding reasonable EPA's explanation that "cost of compliance is only one of the four statutory requirements for reasonable progress analysis.").

(ii) EPA inappropriately revised Entergy's control cost analysis by eliminating consideration of proper costs.

EPA's cost estimates are artificially low because they fail to account for key considerations. As discussed above in Section III.A.2, EPA unjustifiably revised important aspects of Entergy's Revised White Bluff BART Analysis, upon which the reasonable progress controls cost analysis for Independence is based. At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B.

As discussed in Section III.A.3 above, S&L estimated that the costs of dry FGD at White Bluff Units 1 and 2 would be over \$1 billion, which is approximately 220% higher than EPA's estimate. Based on the 2015 S&L FGD Cost Estimate, and assuming a 30-year life for the dry FGD systems at Independence and identical costs, this results in an average cost effectiveness at Independence Unit 1 of \$4,234 and of \$3,909 at Independence Unit 2, which, as noted above, is much higher than cost per ton thresholds EPA rejected for reasonable progress determinations in other states. As importantly, the cost per deciview improvement that would result from installing these controls is estimated at approximately \$1.33 billion at Caney Creek and \$1.53 billion at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Such a massive investment cannot be justified in light of the continuous improvement in visibility being achieved at both Caney Creek and Upper Buffalo.

D. EPA Should Adopt Entergy's Proposed Alternative Approach For White Bluff And Independence.

EPA has requested public comment on any alternative SO_2 and NOx control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. 80 Fed. Reg. at 18,997. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures at the four units that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. *See id.*

1. EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress.

EPA has offered no legal basis for its claim that an alternative four-unit approach must achieve *greater* reasonable progress than the controls that EPA has proposed, 80 Fed. Reg. at 18,997, and Entergy disagrees that such a requirement is applicable or mandated by the Clean Air Act or EPA's own Regional Haze Rule. Neither the Act nor EPA's rules impose such a requirement. To the contrary, EPA noted in the final Regional Haze Rule that states have discretion to determine what control measures must be implemented to achieve reasonable progress. 64 Fed. Reg. at 35,721. EPA further explained that "States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." *Id.* Indeed, not only is it up to the states to determine how much must be done to ensure reasonable progress, but states conceivably could conclude that *nothing* must be done. There is no provision setting a "floor" for reasonable progress.[44]

2. Entergy's proposed approach achieves virtually identical visibility benefits as the Proposal for over $2 billion less.

Entergy is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy also is proposing to meet lower SO_2 emission rates at all four units by 2018, and proposes to install LNB/SOFA at all four units and meet a 30-day rolling average NOx emission rate of 1,342.5 lb NOx/hr, within three years after the effective date of the final FIP.[45] This combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's Proposal but at a cost of over $2 billion less than the Proposal. *See* Figures 13 and 14 below, which compare the projected 2018 haze index at each Arkansas Class I area based on the Ranked Statistical Analysis, to the

[44] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation of source-specific BART, 40 C.F.R. § 51.308(e)(2), Entergy is not proposing a BART alternative. Rather, under Entergy's four-unit approach, the NOx control measures and lower SO_2 emission rate proposed for White Bluff would constitute BART for White Bluff while the NOx control measures and lower SO_2 emission rate proposed for Independence are more than sufficient for reasonable progress purposes for this planning period.

[45] Entergy's rationale for the proposed NOx rate is discussed in Section III.E. below.

deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of the Proposed FIP controls at all BART sources and Independence. Based on Entergy's modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 at Upper Buffalo; differences that are too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

Figure 13

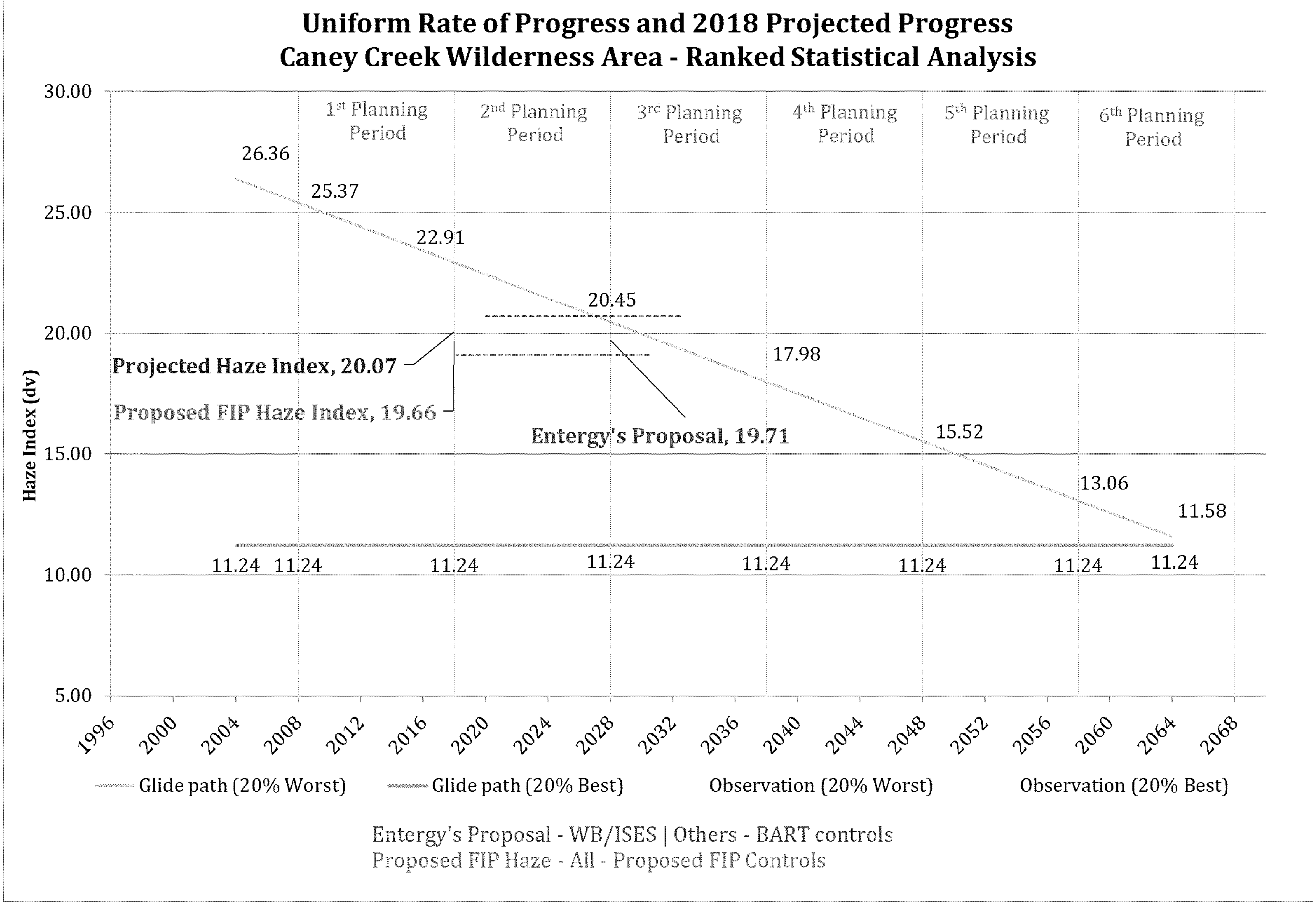
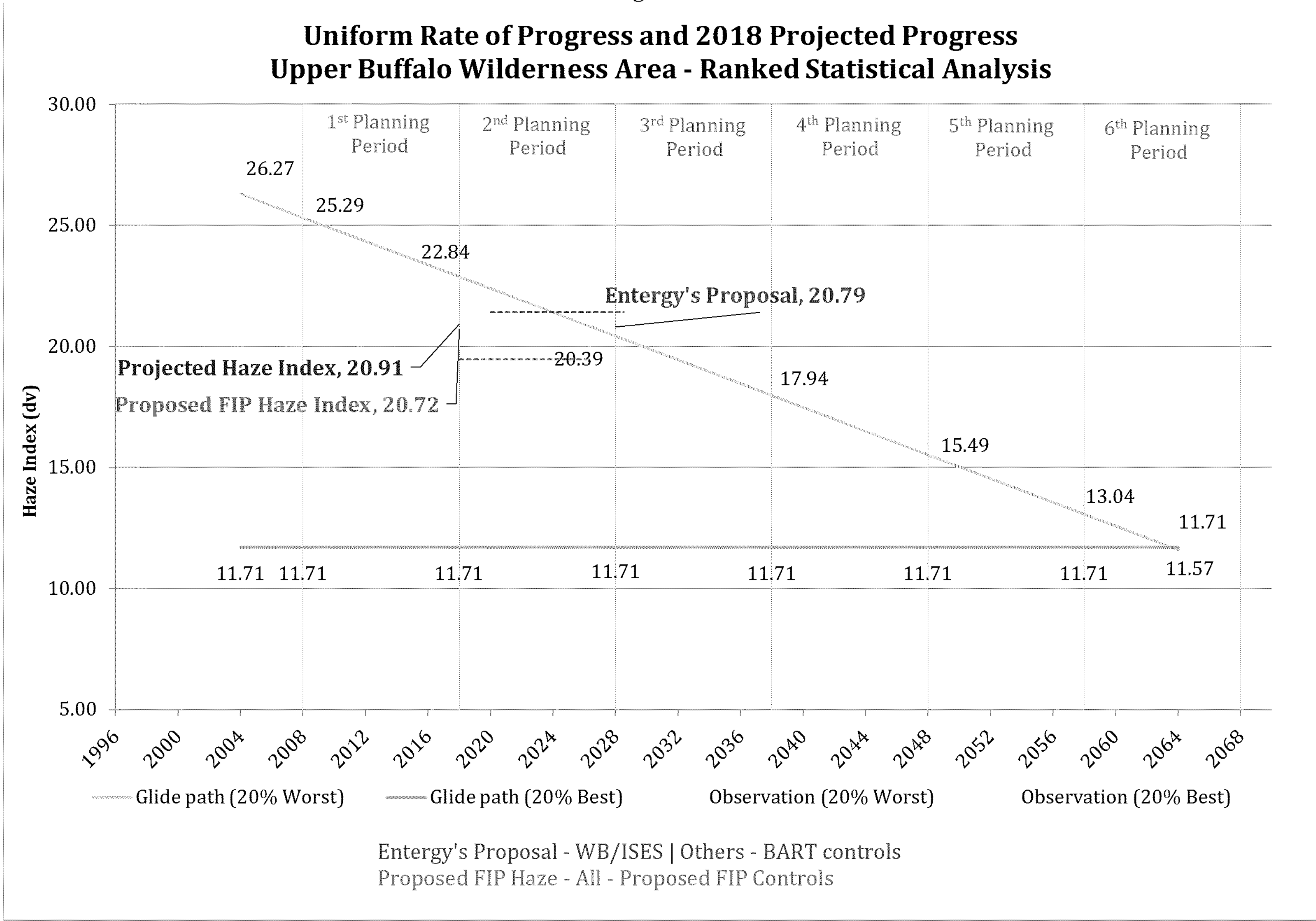

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
Proposed FIP Haze Index, 19.66
Entergy's Proposal, 19.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Figure 14


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
Entergy's Proposal, 20.79
20.39
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
17.94
15.49
13.04
11.71
11.71 11.71 11.71 11.71 11.71 11.71 11.71 11.57
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Entergy's proposed approach with respect to White Bluff and Independence makes sense in light of the long-term objectives of the Regional Haze Program, the high capital costs for scrubbers, and the significant long-term environmental co-benefits from the cessation of coal-firing at the White Bluff units. Arkansas' Five-Year Progress Report demonstrates that the state currently is below the glide path for Caney Creek and Upper Buffalo, and expects to remain so through at least 2018. *See* Section III.C.1 above. Entergy's approach would help ensure that Arkansas remains below the glide path throughout the second planning period, and will produce very large additional reductions in NOx, SO_2, and PM heading into the third planning period.

Ultimately, Entergy's approach would achieve more than 170,000 tons of NOx reductions from White Bluff than the proposed FIP would achieve. While scrubbers would reduce SO_2 emissions substantially, the total visibility benefits from ceasing to use coal are at least as great. Entergy's approach also would achieve multi-pollutant co-benefits. Prior to 2028, SO_2 and NOx would be reduced, which would result in reductions in ozone and $PM_{2.5}$. Starting in 2028, Entergy's approach would produce even greater reductions in emissions of SO_2, NOx and $PM_{2.5}$, as well as achieving reductions in mercury and other hazardous air pollutants, and CO_2/CO_2e. It would reduce annual greenhouse gas emissions by approximately 11.74 million tons per year, a 275 million ton lifetime benefit over EPA's Proposal. Additionally, the elimination of coal combustion in 2027 and 2028 would reduce rail and truck traffic, allow for the closure of landfills, and reduce water usage, in addition to other environmental benefits.

3. EPA should adopt RPGs for Arkansas that reflect Entergy's proposal.

Entergy opposes the RPGs that EPA has proposed for Caney Creek and Upper Buffalo. The RPGs reflect the approved portions of Arkansas' Regional Haze SIP, the proposed FIP BART controls, and the controls proposed for Independence. 80 Fed. Reg. at 18,997. For all of the reasons discussed above in Section III.C, controls at Independence for reasonable progress purposes are not justified and including the emissions reductions based on the installation of dry FGD and LNB/SOFA at Independence renders EPA's RPGs arbitrary and capricious. EPA should recalculate the RPGs based on Entergy's proposed approach for controlling emissions at White Bluff and Independence.

E. The Proposed NOx Limits For White Bluff And Independence Cannot Be Achieved Based On The Plants' Current Operating Conditions.

The NOx emission limits proposed by Entergy for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis,[46] Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are

[46] Entergy notes that EPA relied upon the Revised White Bluff BART Analysis to evaluate controls for Independence.

dispatched to operate and the operating load (MW) for each unit. Initially the MISO operating environment resulted in similar unit dispatch schedules for White Bluff and Independence, with all four units primarily dispatched as base-load units with some load-following operation. However, beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity.

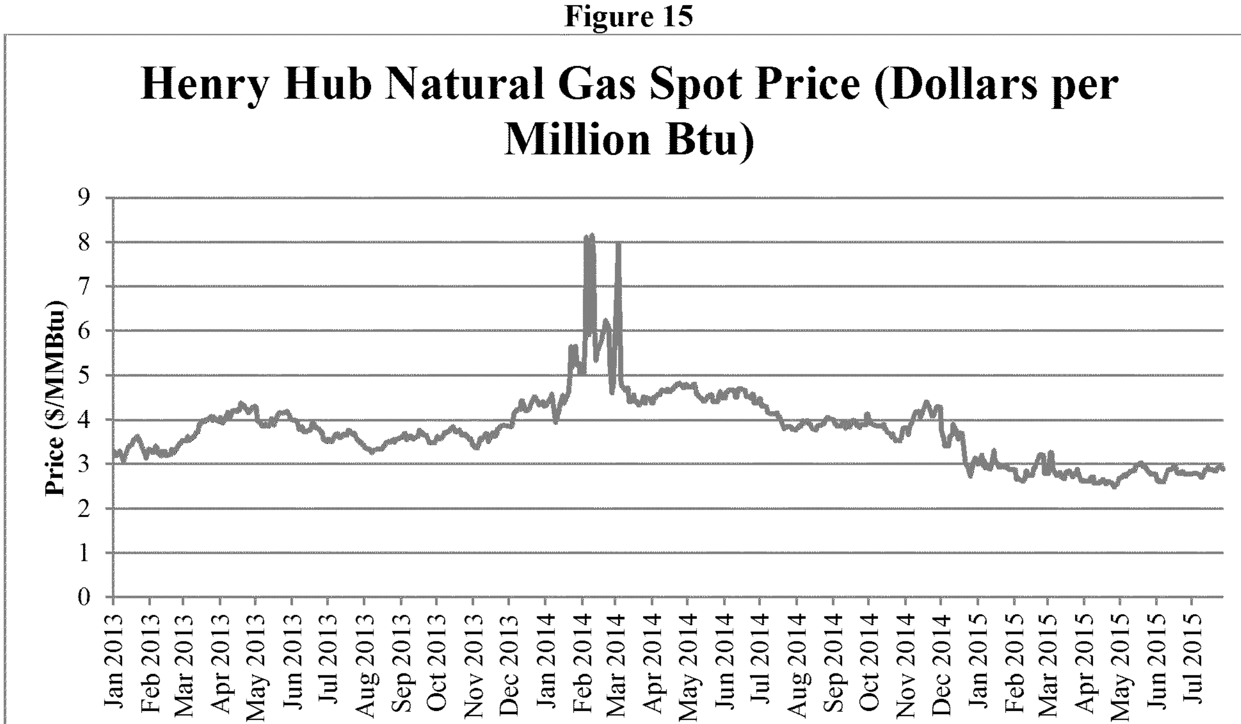
The impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity.

	WB1		WB2		ISES1		ISES2	
	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load
2013	624	7.96%	606	7.95%	797	10.99%	979	11.60%
2014	959	12.39%	784	10.32%	818	10.39%	1069	13.69%
2015 (YTD)*	1444	42.84%	681	27.54%	1278	48.03%	1267	49.40%

* 2015 YTD represents Jan-June 2015

This change in dispatch coincided with a sharp drop in natural gas prices which can be seen in Figure 15 below. This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future.

Figure 15



This change in dispatch for the units at both White Bluff and Independence is significant with regard to NOx emissions as the LNB/SOFA system is designed to operate primarily in the range of 50-100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50-100% of unit capacity.[47] Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NOx emission rates. This memorandum is attached as Exhibit G to these comments. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance.

This was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

The concern arises from low-load operation during which periods of higher NOx emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

To address the potential for a higher NOx emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NOx emission limit for each unit at both White Bluff and Independence as follows.

> For all unit operation (0-100% of capacity), a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average.
>
> And;

[47] This range is referred to as the "control range" by Foster Wheeler. *See* Exhibit F, p. 46, for Foster Wheeler's emissions guarantee. The load ranges identified in the emissions guarantee equate to 50% to 100% of the White Bluff units' operating capacity. Entergy added .01 lb/MMBtu to Foster Wheeler's emissions guarantee to account for fluctuations in NOx emissions from the units. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures and flue gas velocities. A compliance margin above the vendor's emissions guarantee is recommended for establishing an enforceable limit to address such fluctuations.

For unit operation at 50-100% of capacity, a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.

This alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50-100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NOx emission reductions.

F. The NOx BART Determination For Lake Catherine Unit 4 Should Be No Controls.

1. Visibility Improvement From Controls On Lake Catherine Unit 4 Cannot Be Reasonably Anticipated.

EPA has proposed NOx BART controls for Lake Catherine Unit 4 based on the installation of burners out of service ("BOOS"). *See* 80 Fed. Reg. at 18,978. To justify the visibility improvement resulting from installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system without assessing the reliability of the model to predict very small changes in visibility. In *NPCA*, the Ninth Circuit concluded that EPA had failed to justify that predicted visibility improvements were "reasonably anticipated," as required by the Clean Air Act, where the improvements were so insignificant that they were within the CALPUFF model's margin of error. *NPCA*, 788 F.3d 1134, 1146-47.

On behalf of Entergy, Trinity completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4. As part of this analysis, Trinity modeled the following three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three modeling scenarios. Trinity compared the regional haze design value format of average W20 days visibility for this analysis. Specifically the following comparisons were made:

- Modeled vs Measured W20 Days: The W20 days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.

- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.

- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

A complete discussion of Trinity's analysis and results is presented in *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015). ("CALPUFF Margin of Error Report"), which is attached as Exhibit H and is hereby incorporated by reference. As demonstrated in the CALPUFF Margin of Error Report, the Pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NOx BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within this margin of error. *See* 80 Fed. Reg. at 18,978, Table 42. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls for Unit 4 cannot "reasonably be anticipated." 42 U.S.C. § 7491(g)(2); *see NPCA*, 788 F.3d 1134, 1146-47. Accordingly, EPA has not adequately demonstrated that it is appropriate to require NOx BART controls on Lake Catherine Unit 4.

2. Source-Specific Controls Should Not Be Imposed On Lake Catherine Unit 4.

If EPA finalizes a determination that Lake Catherine Unit 4 should be subject to NOx BART controls, EPA should not impose source-specific NOx controls on Lake Catherine Unit 4 but should instead find that CSAPR is better than NOx BART in Arkansas for all EGUs, as discussed in Section III.A.4 above. Compliance with CSAPR will ensure that NOx emissions from Arkansas' EGUs are limited and will improve visibility in Arkansas' Class I areas.

EPA also had evaluated controls other than BOOS for Lake Catherine Unit 4. *See* 80 Fed. Reg. at 18,976-78. Similar to BOOS, however, these controls would result in imperceptible visibility improvements in Arkansas' Class I areas. Although Entergy did not evaluate the margin of error with respect to the CALPUFF predicted visibility improvement from these other controls, EPA had rejected these controls as NOx BART for Lake Catherine Unit 4 based on costs and Entergy agrees with EPA's determination that these controls should not be considered as NOx BART for Lake Catherine Unit 4. Specifically, Entergy agrees with EPA that the incremental cost effectiveness of installing LNB/SOFA at Lake Catherine Unit 4 cannot be justified as BART. *See id.* at 18,978. Similarly, the installation of LNB/SOFA and selective non-catalytic reduction ("SNCR") or selective catalytic reduction ("SCR") cannot be justified as

BART based on either average cost effectiveness or incremental cost effectiveness. *Id.* Lake Catherine Unit 4 is a peaking unit and operated at only a two percent capacity factor in 2014.[48] The estimated incremental costs of installation of LNB/SOFA (at $14,246/ton), SNCR (at $16,029/ton), and SCR (at $11,767/ton) are simply not warranted for a unit that operates so infrequently. *See id.* at 18,978. Installation of these controls would require a massive capital investment and significant operation and maintenance costs that are impracticable for a peaking unit.

G. EPA Improperly Considered The Cumulative Visibility Improvement At All Class I Areas.

EPA's reliance on a "cumulative visibility improvement" metric is arbitrary and capricious, and has no basis in law. In assessing the visibility improvements that are predicted to be achieved through the installation of proposed controls at White Bluff, Lake Catherine, and Independence, EPA totaled the predicted improvements at all affected Class I areas to yield a cumulative visibility improvement associated with each facility. *See* 80 Fed. Reg. at 18,972 (Tables 34 and 35); 18,974 (Tables 37 and 38); 18,978 (Table 42); 18,994 (Table 64). EPA appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed NOx BART determination for Lake Catherine. 80 Fed. Reg. 18,978 (where EPA identified the cumulative visibility impact in its rationale for the Lake Catherine "Proposed NOx BART Determination"). It is improper for EPA to rely upon the cumulative visibility improvement across all affected Class I areas. BART and reasonable progress determinations instead should be based on the predicted visibility improvements at individual Class I areas.

The preamble to the BART Guidelines states that the focus of an analysis of visibility improvements associated with BART controls is to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,170 (July 6, 2005) ("One important element of the [modeling] protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source.") (emphasis added). While the Rule allows consideration of impacts at other nearby Class I areas, it is for the purpose of "determin(ing) whether effects at those areas *may be greater than* at the *nearest* Class I area." *Id.* (emphasis added). Summing the predicted visibility improvements at multiple Class I areas does not facilitate a determination that effects at more distant Class I areas are more significant than those at the closest Class I area.

In addition to having no basis in EPA's own regulations, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls. For example, EPA appears to have selected BOOS as NOx BART for Lake Catherine in part because it would achieve a cumulative visibility improvement across the four affected Class I areas of 1.215 dv. 80 Fed. Reg. at 18,978. But the cumulative metric masks the

[48] Entergy's current resource planning assumption is that Lake Catherine Unit 4 will be de-activated in mid-2025, though no final decision to this effect has yet been made.

fact that no individual Class I area would experience any discernible visibility improvement. Instead, Mingo would experience a 0.196 dv improvement, Hercules-Glades would experience a 0.175 dv improvement, Upper Buffalo would experience a 0.248 dv improvement, and Caney Creek would experience a 0.596 dv improvement. *See id.* These are imperceptible levels of improvement that do not justify installation of controls.[49] The metric therefore equates imperceptible visibility "benefits" in different areas with a much larger and indisputably discernible visibility improvement in a single area.

On a practical level, reliance on a cumulative visibility improvement is illogical. Deciview improvements at multiple areas cannot be added together to form a meaningful metric. As discussed in Section III.C.2 above, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in visibility perceptible to a human observer. Deciviews cannot be directly added or subtracted. To add or subtract the haze, one must add or subtract the total extinction values and then recalculate the haze index in deciviews. Considering the Class I areas addressed in the Proposal are hundreds of kilometers away from each other, particles from one Class I area cannot contribute to or improve the light extinction at another Class I area, therefore, adding or subtracting light extinction values is not an accurate representation of reality and would be illogical. In simple terms, a visitor to a Class I area cannot benefit from any visibility improvement that might be occurring at another Class I area. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the Regional Haze Program: to reduce human perception of visibility impairment in Class I areas. This cumulative visibility metric should be eliminated from any consideration of whether proposed controls will result in visibility improvement, including for the Lake Catherine BART analysis.

H. EPA Must Address The Requirements Of Executive Orders 12866 And 13211.

EPA claims that the Proposal is not a "significant regulatory action" under Executive Order 12866. 80 Fed. Reg. at 18,999. Entergy disagrees. The Proposal's implementation cost to EAI alone of over $2 billion exceeds the $100 million threshold for economic significance. "By virtue of [the] longstanding Executive Order [12866] applying to significant rules issued under the Clean Air Act (as well as other statutes), the Agency must systematically assess the regulation's costs and benefits." *Michigan v. EPA*, 135 S.Ct. at 2715 (Kagan, J. dissenting). EPA states that the Proposal is not generally applicable, and therefore not subject to Executive Order 12866, because the rule "only proposes source specific requirements for particular, identified facilities (six total)." 80 Fed. Reg. at 18,999. However, a count of the number of entities regulated under a rule is not indicative of the general applicability or the significance of the economic impacts of the rule. Requiring additional controls at power plants initiates a cascade of impacts, including changes in the regional distribution of electricity and rates of thousands of electricity customers in multiple states. These far-reaching impacts merit

[49] As discussed above in Section III.F.1, EPA did not perform an analysis to confirm that the model predictions are not within the model's margin of error and, therefore, EPA has not justified that the predicted visibility improvements are "reasonably anticipated."

classifying the Proposed FIP as a regulation with general applicability and significant economic impact.

Entergy also disagrees with EPA's conclusion that the Agency is not required to assess the energy impacts of the Proposed FIP under Executive Order 13211. 80 Fed. Reg. at 19,000. The Proposal will have a significant impact on the supply, distribution, and use of energy. Installation of additional controls will require outages at multiple power plants, altering the normal supply and distribution of energy. Additionally, the more than $2 billion cost of implementing the Proposed FIP will be imposed upon EAI's customers and co-owners, impacting energy use as electricity rates climb.

EPA must prepare a cost/benefit analysis and evaluate the energy impacts of the Proposed FIP and issue these analyses for public comment before finalizing the FIP.

I. Additional Comments.

- Entergy agrees with EPA's proposal that the existing emission limits at the White Bluff Auxiliary Boiler satisfy BART for SO_2, NOx, and PM. 80 Fed. Reg. at 18,975.

- Entergy agrees that 2009-2011 should be used as the baseline period for NOx for White Bluff Units 1 and 2. 80 Fed. Reg. at 18,969.

- If EPA finalizes a source-specific NOx BART limit for Lake Catherine Unit 4, Entergy requests that EPA confirm that the unit may continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit. In the Proposal, EPA appears to have assumed that Unit 4 currently operates "full" NOx CEMS with a continuous NOx analyzer pursuant to 40 C.F.R. Part 60. However, because Unit 4 meets the definition of a peaking unit under 40 C.F.R. Part 75, and the unit is not subject to any NSPS Part 60 standards, Entergy does not currently operate a NOx analyzer for the unit. Under Part 75, Unit 4 qualifies as an Appendix E unit, allowing the unit to utilize a NOx correlation curve to estimate emissions and only monitor heat input and exhaust O_2 concentration.

- Entergy agrees with EPA's conclusion that wet scrubbers do not constitute BART for White Bluff and should not be installed at Independence to meet reasonable progress requirements. 80 Fed. Reg. at 18,972, 18,993.

- Entergy agrees with EPA that LNB/SOFA/SNCR or LNB/SOFA/SCR cannot be justified as BART for White Bluff based on the incremental cost effectiveness of the controls. 80 Fed. Reg. at 18,974.

- Entergy disagrees that the proposed regional haze FIP will satisfy the requirements of CAA Section 110(a)(2)(D)(i)(II), 80 Fed. Reg. at 18,998, for the reasons explained in Entergy's comments on EPA's proposed disapproval of Arkansas' SIP revision addressing interference with other states' programs for visibility protection for the 2006 revised 24-hour $PM_{2.5}$ NAAQS. These comments are attached as Exhibit I and are hereby incorporated by reference.

IV. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed FIP. Entergy strongly urges EPA to adopt a comprehensive approach to regional haze that would involve the four coal-fired units at Independence and White Bluff, as Entergy as proposed, without requiring expensive, unnecessary scrubber technology. Such an approach would ensure superior, long-term visibility benefits than would the Proposed FIP. It also would deliver important non-haze environmental benefits, including a dramatic decrease in GHG emissions, large reductions in SO_2 emissions that also contribute to long-range $PM_{2.5}$ issues, and large reductions in ozone (and $PM_{2.5}$)-forming NOx emissions. Entergy respectfully requests that EPA amend the Proposed FIP as described in these comments.

Respectfully submitted,

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ENTERGY ARKANSAS, INC.

REVIEW OF EPA'S COST ANALYSIS FOR ARKANSAS REGIONAL HAZE PROPOSED FEDERAL IMPLEMENTATION PLAN

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ATTACHMENTS

EXECUTIVE SUMMARY

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[1] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

Cost-effectiveness is influenced by two variables: the total annualized cost to retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable.

Based on our review, the following items in EPA's analysis were identified to result in overstating the tons of SO_2 removed:

- After defining a baseline SO_2 emission period of between 2009 and 2013, EPA arbitrarily excluded the years with the maximum and minimum annual averages;
- When calculating SO_2 emission reductions due to FGD retrofits, EPA incorrectly used maximum monthly averages for baseline SO_2 emissions; and
- A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities.

In addition, the following items in EPA's analysis were identified to result in understating the annualized cost of the dry FGD retrofit:

- EPA subtracted over $23 million in BOP costs for both units because they mistakenly believed the equipment to be included in Alstom's scope;
- Because EPA mistakenly removed BOP cost items that should be included in the estimate, they over-estimated and misapplied percent reductions to other cost items, resulting in cost subtractions of over $7 million for both units;

[1] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

- EPA removed over $41 million per unit in Owner's Costs despite the fact that these are real costs that the Entergy will incur;
- EPA under-estimated cost escalation, and in some cases de-escalated costs, by relying on cost indices rather than using vendor pricing information, all of which resulted in under-estimating costs by more than $42 million per unit;
- EPA incorrectly utilized the IPM model, which is not designed to evaluated site-specific costs, to verify O&M costs at White Bluff;
- EPA scaled capital costs to a design fuel of 0.68 lb/MMBtu, which when compared to operating data, is completely insufficient to ensure compliance with the proposed emission limits for nearly half of the time;
- While we agree that O&M costs should be based on 0.68 lb/MMBtu, EPA's methodology to scale direct O&M costs based on fuel sulfur levels is incorrect and resulted in under-estimating these costs by over $5 million per unit;
- EPA incorrectly scaled indirect O&M costs using fuel sulfur levels, despite these costs being estimated as percentages of capital cost, which resulted in under-estimating these costs by over $4 million; and
- EPA used a remaining useful life of 30 years, when Entergy is proposing to cease coal-fired operations on these units in 2027 and 2028, resulting in a remaining useful life of 6 or 7 years.

As discussed above, S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits. To better address EPA's questions on scope and cost items which it did not understand, S&L has prepared an updated cost report to clarify and provide further detail around scope items and cost items included in the estimate.[2] The corrected and updated cost-effectiveness for both White Bluff units is greater than $7500/ton, which is clearly not cost effective.

With respect to EPA's Reasonable Progress Goal (RPG) analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is over $1.3 billion/Δdv for Caney Creek and over $1.5 billion/Δdv for Upper Buffalo, which is clearly not cost effective.

[2] *See* S&L Report #012831 ("White Bluff Dry FGD Cost Estimate and Technical Basis") (July 2015).

1. INTRODUCTION

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[3] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

S&L's experience in the electric power industry, as well as our experience with the Entergy facilities makes us uniquely qualified to perform this review. S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with various FGD technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, and 25 dry sorbent injection (DSI) projects, all of which are technologies that are used to control SO_2 emissions. Our first-hand experience with these technologies provides us with a thorough understanding of both capital and operating and maintenance (O&M) costs associated with these technologies, as well as providing us with a comprehensive understanding of the achievable emission rates and limitations of these technologies.

S&L's analysis reveals that EPA overstates the cost-effectiveness (\$/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. Cost-effectiveness is influenced by two variables: the total annualized cost of retrofit dry FGD systems (\$/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits.

[3] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

2. Comments to the FIP TSD – SO_2 Emission Reduction Errors

The majority of S&L's comments are relative to EPA's Cost TSD; however, we note that in its FIP TSD, EPA incorrectly estimates both baseline emissions and SO_2 emission reductions that would result from the retrofit of dry FGD systems at White Bluff station. In addition, in proposing emission rates for White Bluff station, EPA proposed SO_2 emission limits that are consistent with performance guarantees offered by dry FGD suppliers during initial performance testing, not emission rates that are achievable over the 30-year life EPA assumed in its analysis. The following sections describe EPA's flawed analysis contained in the FIP TSD.

2.1 Baseline Emission Rates

Although baseline emission rates identified in Entergy's original BART analysis[4] were calculated based on the average annual emission rates from 2001 to 2003, in the FIP TSD, EPA redefines baseline emission by using a 3-year average of annual average SO_2 emissions from the years 2009 to 2013, excluding the years with the maximum and minimum annual averages.[5]

We can find no reason to reject EPA's selection of 2009 to 2013 as the baseline period as it represents more recent operation. However, the approach used by EPA to exclude the maximum and minimum values is entirely arbitrary and EPA does not explain how this approach represents a more realistic depiction of anticipated emissions from the existing sources.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source."[6] In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period.[7] However, EPA provides no explanation or analysis to demonstrate that the approach taken results in a realistic depiction of anticipated annual emissions from White Bluff and Independence. In addition, there is no basis for concluding that EPA's approach of excluding actual emissions data more accurately represents the actual operation of the units. Finally, to our knowledge, with the exception of EPA's proposed Texas FIP, this approach has not been used previously by EPA as a methodology for evaluating baseline emissions in other evaluations (and even if EPA had done so, it is not justified here).

The following table shows a comparison between the baseline emissions as established using EPA's approach and baseline emissions calculated as a straight average for various timeframes within the 2009-2013 period.

[4] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas, October 2013, Trinity Consultants.
[5] *See* EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, under Annual Emissions.
[6] 40 CFR Part 51 Appendix Y.
[7] *Id.*

Table 1: Comparison of Baseline SO_2 Emissions for White Bluff and Independence

Unit	EPA Approach 3 Year Average* (tons)	3 Year Average 2009-2011 (tons)	3 Year Average 2010-2012 (tons)	3 Year Average 2011-2013 (tons)	5 Year Average 2009-2013 (tons)
White Bluff 1	15,816	15,745	15,395	15,826	15,939
White Bluff 2	16,697	15,582	15,217	16,697	16,034
Independence 1	14,269	14,160	15,486	14,707	14,258
Independence 2	15,511	14,673	15,196	16,035	15,407

*EPA's approach includes 2009-2013 3-year average, excluding maximum and minimum years.

With the exception of White Bluff 1, EPA's approach of eliminating the maximum and minimum values results in higher baseline SO_2 emissions compared to averaging the entire 5-year period. In all cases, there is at least one other approach that would result in lower baseline SO_2 emissions compared to EPA's approach. By overestimating the baseline SO_2 emissions, EPA overstates the amount of SO_2 that would be removed and, thus, overstates the cost-effectiveness of the FGD retrofit projects.

2.2 SO_2 Emission Reduction

SO_2 emission reductions were estimated incorrectly by EPA for White Bluff and Independence. For each unit, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. This methodology is incorrect because it assumes the baseline emissions calculated in the previous section are based on maximum monthly averages, which are significantly higher than the annual averages actually used to calculate baseline emissions.

The correct way to project the SO_2 emission reduction is to multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the baseline period. For example, the average heat input to White Bluff 1 over the baseline period of 2009 to 2013 was 55,829,551 MMBtu/year. Multiplying by 0.06 lb/MMBtu and then converting from pounds to tons results in estimated SO_2 emission reductions of 14,264 tons per year, as compared to EPA's 14,363. This method has been utilized by S&L on previous BART analyses, and has been accepted previously by EPA.

Table 2: SO_2 Emission Reductions for White Bluff and Independence

Unit	EPA Approach Using Maximum Monthly SO_2 emission and 3-Year Baseline (tons)	Using 5-Year Average Heat Input and Baseline (tons)
White Bluff 1	14,363	14,264
White Bluff 2	15,221	14,353
Independence 1	12,912	12,607
Independence 2	13,990	13,655

Table 2 compares EPA's incorrect methodology to estimate SO_2 emission reductions at the Entergy Units to the more accurate methodology described above of using the 5-year average heat input from the baseline period. EPA's methodology overestimated the SO_2 emission reduction in all cases and therefore overstates the cost-effectiveness of the FGD retrofits at each unit.

2.3 SO_2 Emission Rate

EPA proposed SO_2 emission rates based on the assumption that a retrofit dry FGD will achieve a controlled SO_2 emission rate of 0.06 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. In several places, EPA cites the IPM dry FGD cost development document, which states: the "[r]ecommended SO_2 emission floor = 0.08 lb/MMBtu."[8]

EPA's proposal is too stringent to be achievable with the retrofit of an existing unit. A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM dry FGD document, the 0.06 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from dry FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

Dry FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler.

[8] Sargent & Lundy LLC, *IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology*, March 2013.

Furthermore, as shown in Table 3, S&L investigated permit limits for dry FGD projects for Spray Dryer Absorber (SDA) projects similar to the dry FGD technology proposed for the White Bluff units, and Circulating Dry Scrubber (CDS) technology, which are more efficient dry scrubber systems because of increased flue gas and reagent contact through the use of a fluidized bed. As indicated, the lowest permit value for all units retrofitting dry FGD systems with averaging periods of 30 days was 0.09 lb/MMBtu, and that includes the more efficient CDS dry FGD systems. The last unit shown in the table includes the lowest permit limit of any of the dry FGD systems listed, but this value still contains the necessary margin because the averaging period is much longer (i.e. 12 months), and because the dry FGD system was installed as part of a new boiler project, so it was incorporated into the new unit design which inherently minimizes some of the design challenges associated with retrofitting, where non-ideal layouts can lead to non-ideal flow distribution inside the absorbers.

Projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.06 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. As indicated in Table, using a limit of 0.08 lb/MMBtu to provide the recommended margin would still be an aggressive permit limit compared to other dry FGD projects.

Table 3: SO_2 Permit Limits for Dry FGD Projects

Reference Plant	Permit SO_2 Limit	Permit Averaging Period
Plant 1 (SDA)	0.09 lb/MMBtu	30 day rolling
Plant 2 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 3 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 4 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 5 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 6 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 7 (CDS)	0.09 lb/MMBtu	30 day rolling
Plant 8 (CDS)	0.10 lb/MMBtu	30 day rolling
Plant 9 (CDS)*	0.07 lb/MMBtu	12-month rolling average

*This unit was a new unit, not a retrofit

EPA's approach to estimating controlled SO_2 emission rates is incorrect and based on a misunderstanding of the actual performance and operation of dry FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

3. Comments to the Cost TSD – Annualized Cost Errors

S&L's remaining comments are focused on EPA's Cost TSD. Our comments follow the same organization of EPA's Cost TSD document and are contained in the following sections.

3.1 Cost TSD, Section 2 – SDA Cost Analysis Methodology

EPA states that the "Control Cost Manual uses the overnight method of cost estimating, widely used in the utility industry.[9]" To support this conclusion, EPA references its own characterization of the CCM methodology published in the preamble to the Oklahoma Regional Haze FIP.[10] Using the overnight methodology, EPA removed certain costs from the SDA cost estimate, including Owner's costs and interest incurred during the construction period. We disagree that the CCM describes an overnight approach to calculating capital costs. The CCM does not once define or even mention the overnight methodology as being the basis for estimating costs. Rather, the CCM describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

In the Oklahoma rule EPA cited to an Energy Information Administration (EIA) document as support for using the overnight cost estimating concept. In fact, EPA stated that "EIA presents all of its projected plant costs in terms of overnight costs."[11] However, this is a mischaracterization of the methodology the EIA uses to develop capital costs for new power generation. The EIA document upon which EPA relied includes a clarifying footnote that states: "Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational."[12] Therefore, EIA cost evaluations take into account financing costs, including AFUDC, one of the line items EPA insisted that Entergy remove[13] from the SDA capital cost estimate

Finally, EPA states that the overnight method is appropriate for BART determinations "because it allows different pollution controls equipment to be compared in a meaningful manner."[14] However, excluding financing costs will bias the cost-effectiveness comparison toward the high-capital options with extended construction periods. Project financing costs such as AFUDC may be minimal on projects that do not require significant capital and with short construction periods, but can be very significant on projects with large capital costs and extended construction periods. Excluding financing costs from the capital cost estimate results in the high-capital cost option appearing more cost-effective. Including financing costs allows the analyst to compare projects with varying capital requirements and varying construction periods.

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[9] Cost TSD, page 1.
[10] *Id.*
[11] *Id.*
[12] EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010, pg. 2.
[13] *See* August 21, 2013 email from Dayana Medina of EPA Region 6 to Mary Pettyjohn of the Arkansas DEQ.
[14] *Cost TSD, page 1.*

3.2 Cost TSD Section 2.3 – Use of the 2009 Alstom Cost Analysis

EPA invited Entergy to clarify certain issues associated with Alstom's 2010 quotation, including a misunderstanding regarding the scope of the dry FGD vendor's contract. In S&L Report #012831 of our comments, we have included a report that explicitly describes the scope of supply for the dry FGD vendor as compared to the balance of plant (BOP) scope of work. EPA made several incorrect assumptions regarding Alstom's scope that led to incorrect adjustments to the BOP cost estimate, as described in Section 3.3 of our comments. Furthermore, EPA's approach to escalating the Alstom quotation was incorrect as described in Section 3.5 of our comments.

3.3 Cost TSD Section 2.4 – Use of the S&L Balance of Plant Costs

EPA mistakenly subtracted BOP costs because they mistakenly believed the equipment to be included in Alstom's scope. As described in S&L Report #012831, the reagent handling system, which feeds the dry FGD supplier's reagent preparation system were not included in Alstom's scope. The "Dry FGD Island" supplied by the dry FGD vendor includes lime day bins, slakers, slurry transfer tanks, slurry transfer pumps, slurry storage tanks, and slurry feed pumps. The BOP system includes the cost associated with the "Reagent Handling System," which includes a rail delivery and unloading system for the lime, new rail spur, renovation of existing rail spur, delivery shed building, long-term storage silos, and a pneumatic conveying system to transfer the lime reagent from the long-term storage silos to the day bins, which are within the dry FGD vendor's scope.

We agree with EPA's comment that including the NO_X control equipment for Units 1 and 2 was an oversight and should not be incorporated into the Dry FGD estimates.

EPA mistakenly subtracted a total of $1,754,000 from the BOP quote because they mistakenly believed that all of the ductwork to be in Alstom's scope. The Dry FGD supplier's scope only includes ductwork between the dry FGD, the baghouse, and the booster fans. The ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney are within the BOP scope.

EPA mistakenly deleted a total of $255,000 to paint the Chimney because it did not understand this line item. Due to lower temperatures and higher moisture of the flue gas, downwash from the gas is more likely to occur and can lead to acid attack of concrete on the chimney shell; therefore, the costs to apply an acid resistant coating to the top 50 feet of the existing chimney shell was included in the estimate.

EPA mistakenly removed a total of $390,000 for costs associating with replacing and recalibrating the Continuous Emission Monitoring Systems (CEMS). The CEMS equipment reflected in Entergy's BART analysis was required because the existing CEMS was not capable of measuring SO_2 concentrations in the controlled range with Dry FGD technology. The costs included in the original estimate to cover replacement of the existing equipment with new equipment rated for the lower SO_2 concentrations as well as the cost to calibrate and certify these monitors including conducting a Relative Accuracy Test Audit (RATA) test.

Based on these comments, we have corrected EPA's cost subtractions in Table 4.

Table 4: Excluded BOP Costs (Corrected, Total for Both Units)

	Equipment	Material	Labor	Total
Total BOP Cost	\$45,561,000	\$35,120,000	\$80,863,000	\$161,544,000
Eliminate U1 NO_X Equipment	\$3,622,000	\$1,600,000	\$3,073,000	\$8,295,000
Eliminate U2 NO_X Equipment	\$3,622,000	\$1,600,000	\$3,073,000	\$8,295,000
Total Eliminated Cost	\$7,244,000	\$3,200,000	\$6,146,000	\$16,590,000
% BOP Items Reduced	15.90	9.11	7.60	N/A

EPA then adjusted additional cost items in the BOP estimate that were either percentages of the equipment, material, and labor costs or were related to equipment, material, and labor costs. EPA adjusted these items by applying the % reduction in cost of equipment, material and labor. Since EPA mistakenly removed cost items that should be included in the estimate, they over-estimated and misapplied percent reduction to the other items. In Table 4, we correct EPA's adjustments to remaining Entergy BOP costs by employing EPA's methodology but reducing the percentage factors to the values indicated in Table 5.

EPA excluded a total of \$51,733,667 from the estimate, but Tables 4 and 5 show that only \$20,724,543 was justified because NO_X control equipment had been included. Because of EPA's misconception as to the scope of work included in the BOP and Alstom estimates, they mistakenly concluded that costs were double-counted and removed \$31,009,123 (total for both units) in costs that should be included. This resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff.

Table 5: Adjustment to Remaining Entergy BOP Costs (Total for Both Units)

	EPA Cost TSD Reductions				Corrected Reductions*			
DESCRIPTION	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$546,061	$546,061	$0	$0	$656,036	$656,036
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
COST DUE TO OVERTIME - 5-10'S	$0	$0	$7,970,183	$7,970,183	$0	$0	$9,575,359	$9,575,359
COST DUE TO OVERTIME - 5-10'S	$0	$0	$0	$0	$0	$0	$0	$0
PER DIEM - @ $10 PER HOUR	$0	$0	$7,888,659	$7,888,659	$0	$0	$9,477,416	$9,477,416
PER DIEM - @ $10 PER HOUR	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$327,060	$0	$0	$327,060	$400,318	$0	$0	$400,318
FREIGHT @ 5% OF MATERIAL	$0	$0	$0	$0	$0	$0	$0	$0
FREIGHT @ 5% OF MATERIAL	$0	$1,413,404	$0	$1,413,404	$0	$1,596,000	$0	$1,596,000
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
GENERAL & ADMINISTRATIVE (G&A) @ 5% OFMATERIAL AND LABOR	$0	$1,413,404	$2,417,281	$3,830,686	$0	$1,596,000	$2,904,116	$4,500,116
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$1,119,810	$1,119,810	$0	$0	$1,345,337	$1,345,337
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$2,826,809	$4,833,794	$7,660,602	$0	$3,192,000	$5,807,308	$8,999,308
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$2,240,388	$2,240,388	$0	$0	$2,691,597	$2,691,597
NON CONTRACTOR INDIRECTS	$0	$0	$0	$0	$0	$0	$0	$0
ENGINEERING - BOP	$0	$0	$7,579,481	$7,579,481	$0	$0	$9,105,970	$9,105,970
Totals				$40,576,333				$48,347,457
Reduction in Remaining BOP Costs				$11,905,667				$4,134,543
Excluded BOP Costs from Table 4								$16,590,000
TOTAL BOP Reduction								$20,724,543

*Same methodology used as EPA but percentages applied are from Table 4

3.4 Cost TSD Section 2.5 – Undocumented or Disallowed Cost Items

Owner's Costs include a variety of costs incurred by the owner to support the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the Owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs typically include, but may not necessarily be limited to:

- Site investigations (geotechnical, hydrology, etc.) for project design
- Environmental permitting/approvals
- Insurance during construction
- Site security during construction
- Transmission interconnection (if applicable)
- Fuel interconnection (if applicable)
- Owner's mobilization costs
- Owner's project management and support staff
- Insurance advisor
- Labor relations consultant
- Tax consultant
- Financial advisor
- Legal advisor
- Market consultant
- Community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[15] CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems.

To address the items in this section, we included a section in S&L Report #012831 that describes Entergy's Owner's costs and how they were developed. We believe EPA deleted these Owner's costs because EPA did not understand how they were defined and therefore, incorrectly assumed that they did not reflect real costs to Entergy. In total, EPA removed $41,741,743 per unit from the original estimate which should be included. Removing these costs resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff and Independence. Detailed explanations of these costs are included in S&L Report #012831 to help EPA understand

[15] *See*, Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0, prepared by U.S. EPA, September 2009, pages 17 and 34.
Appendix B, pages B-3 and B-6.

these costs.

3.5 Cost TSD Section 2.6 – Escalation

We agree with EPA's assertion that the application of escalation is allowed by the CCM.[16] However, EPA's method of using Chemical Engineering Plant Cost Indices (CEPCI) to escalate costs to the year 2013 resulted in severely underestimating the costs associated with escalation. CEPCI are sometimes used to estimate escalation by multiplying base costs by the ratio of the index for the year costs are to be escalated to the index for the year in which the costs were originally generated. For example, EPA used CEPCI from 2009 (521.9) and 2013 (550.8) to escalate the FGD costs from a 2009 basis to a 2013 basis. Thus, EPA applied the following formula, 550.8/521.9*$247,856,184 to obtain an estimated 2013 FGD cost of $261,581,119 for both units.

Rather than estimating escalation of Alstom's pricing from 2010, S&L (on behalf of Entergy) requested updated FGD pricing from Alstom in 2013[17]. We agree with a reference cited in the CCM and authored by EPA which states, "At best [cost indices] provide a cloudy mirror…there is no substitute for current price information obtained from suppliers of those goods and services."[18] Nothing illustrates EPA's conclusion that cost indices are not to be substituted for supplier information better than comparing EPA's escalation rate to the actual escalation rate indicated in Alstom's budgetary quotations as shown in Table 6.

Table 6: Alstom Quotation Comparison (Total for Both Units)

Parameter	EPA	Vendor Quotation
FGD Cost 2009	$247,856,184	$247,856,184
FGD Cost 2013	$261,581,119	$297,904,000
Average Escalation	1.36%	4.7% per year

As shown in Table 6, EPA underestimated escalation significantly, resulting in underestimating the 2013 dry FGD costs by $36,322,881 (total for both units). In fact, EPA applied CEPCI indices in several instances from 2008 that *de-escalated* costs, resulting in lower costs in 2013 as compared to 2008. We note specifically that EPA's cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs.[19] Table 7 summarizes how EPA incorrectly estimated escalation in its analysis for White Bluff Unit 1 and corrects that by applying an average escalation rate of 4.7% to match the Alstom quotation. We note that information from Alstom showed their pricing escalated nearly equivalently for

[16] *See* Cost TSD, Section 2.6, page 8
[17] Updated FGD pricing from Alstom is used as the basis of the 2015 cost estimate documented in S&L Report #012831.
[18] Escalation Indexes for Air Pollution Control Costs, United States Environmental Protection Agency, October 1995, pp. 3-4.
[19] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Entergy Costs"

equipment/material (~4.8%) and for installation (~4.6%). Since the difference was negligible we applied the average 4.7% in the revised costs shown in Table 7. EPA's underestimation of cost escalation carried through their analysis and resulted in an incorrect reduction in the cost estimate of over $42 million per unit.

Table 7: Summary of EPA's Escalation Errors (Per Unit)[20]

Item	Entergy	EPA (2013)	Corrected Costs Including Escalation (2013)	Escalation Costs Omitted by EPA
Total Contractor Costs* (2010)	$156,974,274	$161,676,662	$180,164,213	$18,487,550
Contingency (2010)	$20,875,711	$21,501,073	$23,959,697	$2,458,624
Balance of Plant (2008)**	$102,085,500	$75,145,724	$115,401,842	$13,316,342
Balance of Plant Indirect Costs (2012) ***	$9,768,175	$0	$10,227,279	$1,494,175
Misc Contract Labor (2012)	$4,583,719	$0	$4,799,154	$215,435
Entergy Internal Costs (2012)	$20,076,644	$0	$21,020,246	$943,602
Capital suspense (2012)	$8,348,276	$0	$8,740,645	$392,369
Total Capital Investment (TCI)		$258,323,459	$319,525,752	
Direct Annual Costs (2008)	$7,901,369	$7,790,140	$9,941,130	$2,150,990
Indirect Annual Costs				
Overhead (2008)	$2,572,707	$2,536,491	$3,236,859	$700,368
Administrative Charges @ 2% of TCI		$5,166,469	$6,390,515	$1,224,046
Property Tax @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Insurance @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Total Indirect Annual Costs		$12,869,429	$16,017,889	
Total Escalation Costs Underestimated by EPA				**$42,607,547**

* This item reflects the updated dry FGD pricing received in 2013
** As EPA did, this item subtracts the excluded BOP costs discussed in Section 3.3 before applying the escalation
*** In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis, SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012 BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA.

[20] *See* Cost TSD, Table 5 on page 10

3.6 Cost TSD Section 2.7 – Operating and Maintenance (O&M) Costs

Although EPA claims in its proposal that it relied on the methods and principals contained within the Control Cost Manual in developing its individual control technology cost estimates, in the supporting Cost TSD EPA stated that "we can compare Entergy's O&M costs to those obtained through the use of our IPM SDA cost model."[21]

The IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital and O&M costs. IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia.[22] The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Standard (MATS). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and S&L developed the cost algorithms used in the IPM model to estimate costs associated with DSI, SDA, and wet FGD control systems.[23] The IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates.

Cost algorithms in the IPM model were developed based on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues.[24] The primary purpose of the IPM cost modules is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but they do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Regarding O&M costs for SDA FGD systems, the IPM model includes the following assumptions that are not consistent with a site-specific O&M cost estimates:

- A fixed quantity of additional personnel to operate the equipment is included, not accounting for site-specific project and staffing needs;

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[21] *See* Cost TSD, Section 2.7, page 9.
[22] *See*, EPA website: www.epa.gov/airmarkt/progsregs/epa-ipm/.
[23] *See*, e.g., IPM Model- Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Sargent & Lundy LLC, March 2013.
[24] *Id.*, at page 1.

- While we agree with the general practice of estimating maintenance material and labor costs as percentage of capital costs, the IPM model does not estimate site-specific capital costs sufficiently upon which to apply this percentage, and the assumed percentage cannot be modified to accommodate project specific requirements;
- The assumptions incorporated in the maintenance material and labor costs are propagated into the administrative labor item, and is therefore limited by the same items as the previous item;
- Reagent consumption assumes a stoichiometry that cannot be modified to match vendor-supplied guarantees for a specific application;
- Reagent consumption also depends upon a flue gas temperature into the SDA of 300°F and cannot be modified to apply site-specific temperatures;
- Reagent consumption also depends upon lime purity, which the IPM model assumes to be 90% and cannot be modified to match actual reagent supply information;
- The IPM model estimates water consumption based on gas flow and fuel sulfur levels instead of performing site-specific calculations using actual fuel properties and operating conditions;
- Waste generation is a function of the assumed lime stoichiometry discussed above as well as an assumed moisture content of 10% that cannot be modified to match vendor-supplied mass balances for specific applications; and
- The SDA flue gas pressure drop estimate included in the IPM model is an average value based on flue gas flow rate and sulfur levels instead of performing site-specific calculations that consider the actual fuel properties, operating conditions, and actual equipment sizing and arrangement.

EPA's use of IPM to benchmark O&M costs is thus not an appropriate choice for a unit-specific analysis consistent with BART guidelines. By relying on the IPM cost modules to verify dry FGD O&M costs, EPA did not adequately evaluate and account for potential project-specific site constraints that Entergy would incur to operate the FGD control systems EPA is proposing. In addition, using the IPM cost algorithms to calculate FGD control system capital or O&M costs is inconsistent with the case-by-case BART cost analysis described in the BART Guidelines for at least two reasons. First, the IPM model does not account for unit-specific design and operating parameters that can affect control system design and costs, including operating costs. Second, the IPM cost equations do not take into consideration site-specific conditions that could affect the O&M costs to operate the control system.

Please see additional comments in the next section of our comments (3.7), addressing EPA's adjustment of the O&M cost estimates to account for lower coal sulfur.

3.7 Cost TSD Section 3.1 – Entergy's Coal Sulfur Assumption

EPA states that an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu at White Bluff is "far in excess of sulfur level of the coals it has historically burned," and concludes, "[t]hus Entergy has costed SO_2 scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs." Based on this conclusion, EPA adjusts the capital and O&M costs using a design sulfur level selected by EPA. While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis.

EPA correctly assumes that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but their conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with BART guidelines.

The SO_2 emission reduction calculation depends upon the baseline emissions, baseline heat input, and the required outlet emission rate (see Section 2.2 of our comments). SO_2 emission reduction does not depend on the fuel sulfur levels selected for FGD system design, neither the BART guidelines nor the CCM address evaluating potential future SO_2 reduction based on design fuels as part of the BART analysis or cost estimating methodology. Therefore, EPA's first conclusion that the higher costs be balanced against greater SO_2 reduction potential is inconsistent with BART requirements and has no basis.

Although the BART guidelines and the CCM both account for the development of a design basis, there are no specific requirements that air pollution control design be tied to historical operating trends. Therefore, EPA's second conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Based on its erroneous conclusions, EPA selected a maximum monthly fuel sulfur level of 0.68 lb/MMBtu as the design basis used to estimate the capital costs. Figure 1 illustrates why the use of White Bluff's maximum monthly fuel sulfur level is completely insufficient. The ability to reduce SO_2 emissions depends critically upon the amount of reagent, or lime that can be added to the FGD system. With a 0.68 lb/MMBtu design basis, the reagent preparation and delivery equipment would be inadequately sized to add lime when sulfur levels increase beyond that level. As shown in Figure 1, EPA's design basis would result in emissions above the proposed emission rate for almost half of the operating time. This design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance. If this is the approach EPA is intending, then the cost analysis would need to be revised to incorporate significant additional costs associated with fuel purchasing limitations. We did not include any additional O&M costs associated with fuel limitations because we believe EPA selected the design basis due to a lack of experience rather than intending to place enforceable limits on fuel purchasing at White Bluff station.

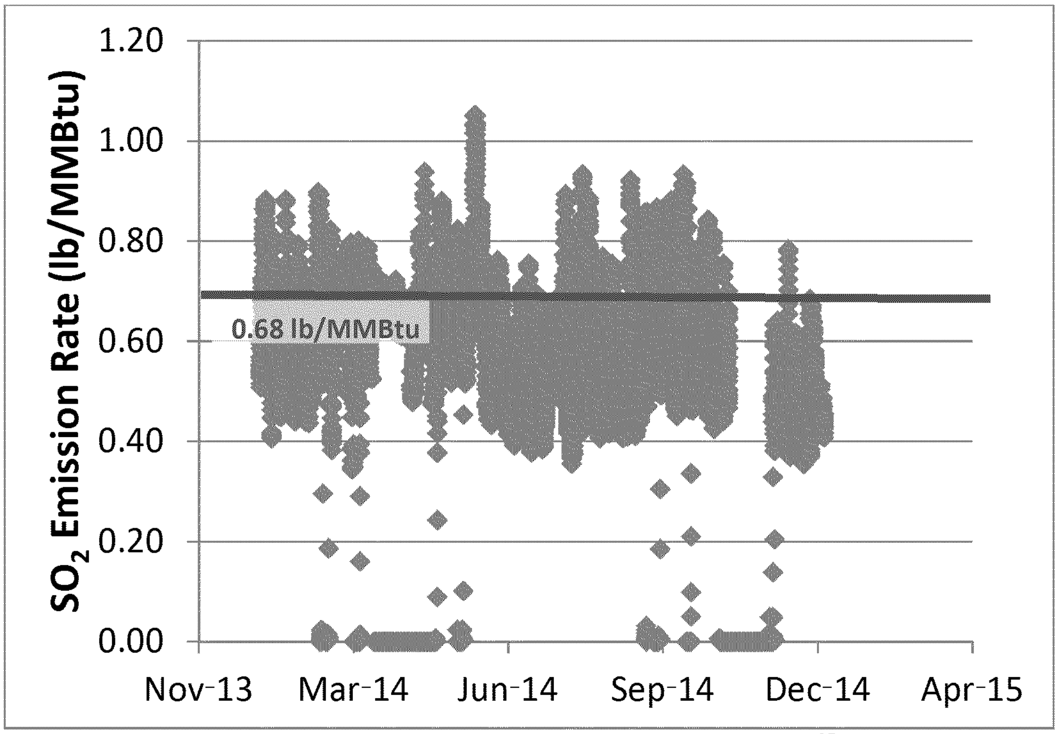

Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

While we believe that the 2008 design basis of 2.0 lb/MMBtu was appropriate at that time based on the potential to fire fuels with higher sulfur levels, based on more recent information, Entergy now believes that they will not purchase fuels with sulfur levels higher than 1.2 lb/MMBtu. The operating data shown in Figure 1 confirms that 1.2 lb/MMBtu would result in a design basis that would ensure continued compliance with EPA's proposed FIP emission rates. Therefore, we have provided a revised cost estimate based on 1.2 lb/MMBtu. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), S&L has included a sensitivity analysis in S&L Report #012831.

As discussed previously, we agree that it is appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. However, EPA's adjustment factor of 0.5823 applied to direct O&M costs severely underestimated these costs. In agreement with EPA's sulfur basis, S&L developed O&M costs for the 0.68 lb/MMBtu operating case in S&L Report #012831 based on site specific consumption rate estimates and unit costs. Our report estimated O&M costs including direct variable and fixed O&M costs to be a total of $10,166,000 per unit in the first year. By comparison, EPA's calculation scales direct O&M costs of $7,790,140 by 0.5823, resulting in direct O&M costs of $4,536,199 per unit being

[25] Downloaded from EPA's Clean Air Market Database.

included in its cost-effectiveness calculation.[26] This methodology underestimated direct O&M costs by $5,629,801 per unit.

In addition, EPA applied the same O&M factor of 0.5823 to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost.[27] Therefore, assuming EPA's capital cost scaling methodology for capital cost is correct (which we do not believe is the case), then EPA should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. EPA's methodology underestimated indirect O&M costs by $4,840,192 per unit.

3.8 Cost TSD Section 4.1 – EPA's Conservatism in Cost Estimating

EPA lists two assumptions it believes are conservative in its Cost TSD. In one assumption, EPA noted that amortization from the 2008 S&L cost analysis was 40 years, but they lowered the remaining useful life to 30 years, which increases the cost-effectiveness. EPA's estimate is not conservative with regard to equipment life because, as EPA states, they, "typically assume a 30 year equipment life for scrubbers,"[28]and the 2008 amortization value from S&L was not intended to be used to conduct the BART analysis. Furthermore, as discussed in Section 3.9, the actual remaining life of these units is far below what EPA assumed.

In the second assumption, EPA concludes that two absorber vessels are not required and, thus, a 7% cost savings that could have been realized was not applied. We do not believe EPA is qualified to design dry FGD systems, and therefore not qualified to evaluate the number of vessels that are suitable for White Bluff. Dry FGD systems of this type have not been applied to units of this size, and the dry FGD supplier quoted three absorber vessels for this application based on their expertise. EPA cites no reference where fewer absorber vessels have been installed for a unit with an identical design basis, and therefore its assertion that two absorber vessels is adequate is arbitrary and without basis.

3.9 Remaining Useful Life

EPA states, "With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for the Entergy White Bluff Plant, nor did Entergy's evaluation indicate any future planned shutdown."[29] Therefore, EPA utilized 30-years as the remaining useful life in its cost-effectiveness calculations. As stated in Entergy's comments to the proposed rule, Entergy proposes to cease coal-firing at the White Bluff units between 2027 and 2028. The proposed rule requires that the FGD controls and White Bluff be operational 5 years after the effective date of the rule. Assuming the effective date of the final rule is one year after the comment period closes, then the White Bluff FGD's will need to be operating by July of

[26] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Cost-Effectiveness" Cell D4.
[27] *Id.*
[28] Cost TSD, Section 4.1 page 16.
[29] AR FIP TSD, p. 80.

2021. Based on the coal-cessation dates of White Bluff Units 1 and 2, the remaining useful life of these FGD systems is therefore between 6 and 7 years, instead of 30 years used in EPA's analysis.

4. Cost TSD Section 5 – Inclusion of Independence under Reasonable Progress Goals (RPGs)

EPA included Entergy's Independence Plant in its RPG analysis based on annual emissions from the facility.[30] It is beyond the scope of S&L's comments to address the basis upon which EPA decided to include Independence in its RPG analysis for Caney Creek and Upper Buffalo. Instead, our comments focus on the inconsistencies and errors included in EPA's RPG analysis for the Independence station.

In EPA's RPG analysis for SO_2 Controls, EPA concluded that the units at White Bluff and Independence Stations are similar enough to apply "the total annualized dry FGD and wet FGD costs [they] developed for the White Bluff units to the Independence units."[31] EPA then calculates the cost-effectiveness to retrofit FGD systems at Independence by adjusting the White Bluff cost effectiveness calculations to account for the differences in SO_2 emissions at Independence. This approach is flawed for several reasons. First, this approach includes all of the errors in EPA's cost-effectiveness analysis for White Bluff as described in the preceding sections, including errors in calculating baseline emissions, errors in calculating emission reductions, and errors associated with estimating annualized costs. Second, applying the White Bluff annualized costs to Independence is inconsistent with EPA's RPG guidance which requires cost estimates based on design parameters be developed for air pollution control systems.

To determine whether air pollution controls would be required at Independence Units 1 & 2 to meet the Reasonable Progress Goals at Caney Creek and Upper Buffalo, EPA conducted an RPG four factor analysis. The four factor analysis is described in EPA's RPG Guidance Document, and includes an evaluation of: (a) costs of compliance; (b) time necessary for compliance; (c) energy and non-air impacts; and (d) the remaining useful life of the source.[32] Regarding the first factor listed, costs of compliance, EPA suggests that, for stationary sources, the following steps be performed:

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emission controls; and

c) Develop cost estimates based upon those design parameters[33]

EPA did not perform steps b and c of the RPG compliance cost evaluation. Rather, EPA relied upon an EIA database comparison as well as an aerial photo comparison of the two units to justify applying the White Bluff FGD costs to Independence. The EIA information does not contain any information that would be used to set the design basis for either FGD system;

30 *See* 80 Fed. Reg. 18,991 (April 8, 2015).
31 *Id.*, at page 18,992.
32 *See* "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," U.S. EPA June 1, 2007, pg 1-3.
33 *Id.*, at page 5-1.

therefore it cannot be used to conclude the FGD system design at Independence would be identical to White Bluff. Furthermore, EPA's use of aerial photos to indicate visual similarities between White Bluff and Independence ignores many site-specific factors that cannot be captured in a Google Earth image downloaded from the internet. Some of the site-specific factors that EPA did not account for by using this approach and which could result in different costs to retrofit FGD technology at Independence as compared to White Bluff include:

- EPA proposes the same timeline for compliance for White Bluff and Independence which will add significant labor costs due to the amount of skilled labor that would be required to construct four FGD systems in the same time period;
- EPA did not review plant operating data, such as flue gas temperatures, which affect flue gas volume, potentially requiring different equipment sizing for Independence;
- EPA did not review operating and maintenance practices at Independence, which could result in different O&M costs;
- EPA did not assess differences in underground utility interferences that could potentially change the equipment arrangement at Independence;
- EPA did not conduct subsurface geotechnical investigations to determine differences in soil conditions or distances to reach bedrock that would impact foundation design or seismic design requirements;
- EPA did not assess other seismic design requirements such as seismic risk or magnitude of potential earthquakes to determine steel design differences that may be required; and
- EPA did not assess differences in wind loads which could impact foundation and structural steel design.

In its guidance document, EPA states, "[f]or additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines."[34] We note that, for EPA's RPG analysis for Independence, EPA did not revisit any of the steps required as part of a BART analysis; therefore, EPA ignored other lower cost technologies or methodologies to reduce SO_2 emissions at Independence station. EPA's inherent assumption is that BART-level SO_2 reductions are required at Independence to meet the RPGs, but it does not adequately support that assumption. EPA modeled visibility impacts of SO_2 reductions assuming FGD systems would be retrofitted at Independence, but they failed to conduct modeling using any other technology or methodology that could provide more cost-effective SO_2 reductions.

Finally, EPA also states in its RPG guidance document that for, "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation."[35] EPA's CENRAP modeling showed that the cumulative benefit of installing all of the controls proposed in the FIP would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv.[36] Considering that

[34] *Id.*, at page 5-1.
[35] *Id.*, at page 5-2.
[36] *See* 80 Fed. Reg. 18,998, Table 67.

Independence represents only approximately 36% of the SO_2 point source emissions and 29% of the point source NO_X emissions in Arkansas, Entergy estimated the visibility improvement due to retrofitting FGD systems at Independence would be approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo. Although we do not support EPA's use of the White Bluff cost estimates for Independence, we applied the White Bluff costs to retrofit dry FGD and the estimated visibility improvement due to retrofitting dry FGD systems at Independence to estimate dollar-per-deciview as suggested in EPA's RPG guidance document. Table 8 shows that retrofitting dry FGD systems at Independence is clearly not cost effective when considering the insignificant visibility improvements.

Table 8: Dollar-Per-Deciview Reduction for Dry FGD at Independence

Class I Area	Caney Creek	Upper Buffalo
Estimated Visibility Improvement[37]	0.08	0.07
Revised Annualized Costs[38]	$106,765,022	$106,765,022
$/Δdv	$1,334,562,775	$1,525,214,600

[37] The CENRAP modeling includes SO_2 and NO_X impacts; therefore, the numbers shown likely overestimate the visibility improvement based solely on SO_2 reductions.
[38] Annualized costs for Retrofitting Dry FGD at White Bluff 1 and 2 from S&L Report #012831 were used assuming a 30-year remaining useful life.

5. CONCLUSION

S&L reviewed the approach EPA takes in its proposed FIP for Arkansas, including EPA's determination of costs for retrofit dry FGD scrubbers, and EPA's evaluation of annual SO_2 emission reductions. Our analysis identifies several areas where EPA overstates the cost-effectiveness ($/ton of SO_2 removed) of the dry FGD retrofits that EPA would require in its FIP. As discussed in this analysis, cost-effectiveness is influenced by two variables: the total annualized cost to retrofit FGD controls ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. Table 9 shows how the approach EPA took understated the annualized cost of the control systems and the adjustments S&L made to correct EPA's errors.

Table 9: Adjustments to EPA's Annualized Cost for a Single Unit at White Bluff

Item	Total Capital Investment ($)	Annualized Cost ($/year)
EPA FIP	$247,537,295	$31,981,230
Corrected BOP Cost Exclusions	$263,041,857	$33,230,898
Corrected Owner's Cost Exclusions	$304,783,600	$36,595,282
Corrected Escalation	$347,391,147	$40,029,450
Corrected Operating Costs	$347,391,147	$50,499,444
Remaining Useful Lifetime Adjustment*	$347,391,147	$86,975,068 to $95,381,830
2015 Estimate (S&L Report #012831)*	**$536,185,000**	**$109,681,936 to $122,657,613**
Differential from EPA FIP*	**+ $99,853,852**	**+ $54,993,838 to $63,400,600**

* Entergy proposes to cease to use coal at White Bluff 1 and 2 between 2027 and 2028; therefore, the annualized costs are shown as a range based on a remaining useful life of 6 or 7 years.

In addition, Table 10 shows how EPA's approach overstated the tons of SO_2 that would be removed by its FIP-imposed dry FGD and the adjustments S&L made to correct EPA's mistakes.

Table 10: Adjustments to EPA's SO_2 Emission Reductions

Item	White Bluff 1 (tons)	White Bluff 2 (tons)
EPA FIP	14,363	15,221
Corrected Baseline Emission Calculation	14,474	14,617
Corrected SO_2 Emission Reduction Calculation	14,264	14,353
Differential from EPA FIP	**-99**	**-868**

EPA's errors resulted in severely overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff 1 and 2 (and then by extension in its reasonable progress analysis for Independence 1 and 2). Table 11 summarizes how EPA's errors systematically underestimated cost and overstated the cost-effectiveness to install these dry FGD systems. As Table 11 indicates when the errors are corrected and updated costs incorporated, retrofitting dry FGD systems at these units is clearly not cost-effective.

Table 11: Summary Cost-Effectiveness Impacts

Item	White Bluff 1 ($/ton)	White Bluff 2 ($/ton)
EPA's Cost Effectiveness	$2,227	$2,101
Corrected Baseline Emission Calculation	$2,210	$2,188
Corrected SO_2 Emission Reduction Calculation	$2,242	$2,228
Corrected BOP Cost Exclusions	$2,330	$2,315
Corrected Owner's Cost Exclusions	$2,566	$2,550
Corrected Escalation	$2,806	$2,789
Corrected Operating Cost	$3,540	$3,518
Corrected Remaining Useful Life *	$6,097 to $6,687	$6,060 to $6,646
2015 Estimate (S&L Report #012831) *	**$7,689 to $8,599**	**$7,642 to $8,546**
Differential from EPA FIP[1]	**+ $5,462 to $6,372**	**+ $5,541 to $6,445**

* Entergy proposes to cease to use coal at White Bluff Units 1 and 2 between 2027 and 2028; therefore, the cost effectiveness values are shown as a range based on a remaining useful life of 6 or 7 years.

With respect to EPA's RPG analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses, to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is **over $1.3 billion/Δdv** for Caney Creek and **over $1.5 billion/Δdv** for Upper Buffalo, which is clearly not cost effective.

SL-012913-Attachment A - Corrected Cost Effectiveness Calculations

White Bluff 1	EPA FIP	Corrected Baseline Emissions	Corrected Heat Input and Emission Reduction	Section 2.4, Excluded BOP Costs	Section 2.5, Excluded Owner's Costs	Section 2.6, Incorrect Escalation	Section 2.7, Corrected Operating Cost	Remaining Useful Lifetime Adjustment (7 Year Life)	Remaining Useful Lifetime Adjustment (6 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 7 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 6 Year Life)
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)[2]	0.65	0.65	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	Not Used	Not Used	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551
Controlled SO2 Emission Rate (%)	90.81	90.81	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	15,816	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939
SO2 Emission Reduction (tons)	14,363	14,474	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264
Cost Effectiveness ($/ton)	$2,227	$2,210	$2,242	$2,330	$2,566	$2,806	$3,540	$6,097	$6,687	$7,689	$8,599
White Bluff 2											
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)	0.68	0.68	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	49,108,824	47,158,824	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262
Controlled SO2 Emission Rate (%)	91.16	91.16	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	16,697	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034
SO2 Emission Reduction (tons)	15,221	14,617	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353
Cost Effectiveness ($/ton)	$2,101	$2,188	$2,228	$2,315	$2,550	$2,789	$3,518	$6,060	$6,646	$7,642	$8,546

1 - EPA did not list the heat input. EPA's analysis incorrectly assumes the annual averageheat input as being the baseline SO_2 emissions (tpy) divided by the monthly maximum emission rate (lb/MMBtu)

2- EPA incorrectly applied the maximum maximum monthly SO_2 emission rate to determine the % reduction in SO_2 to achieve 0.06

3- EPA did not include this item. SO_2 emission reduction is corrected to calculate it as [baseline annual average heat input (MMBtu/Yr)] * [the controlled SO_2 emission rate (lb/MMBtu)]*[2000 lb/ton]

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD
COST ESTIMATE AND TECHNICAL BASIS

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Prepared by

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CONTENTS

EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be \$1,072,370,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately \$10,166,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication
17	June 2018	Physical Flow Model Completed

Month	Date	Milestone
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion
		Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney's outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design.
- SO_2 inlet concentration of 0.68 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.46% (based on Entergy's future operating profile).
- Compliance deadline of December 2020.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. <u>Dry FGD Island</u>
   a. Reagent Preparation System, common to both units:
      - Two lime day bins, 24-hours storage each
      - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks
      - Four slurry transfer centrifugal pumps
      - Two lime slurry storage tanks
      - Four slurry feed centrifugal pumps
      - Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
   - Three absorber vessels per unit, with access doors
   - Rotary atomizers, two spare atomizers included
   - Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
   - Heating and ventilation
   - Vacuum piping
   - SDA Superstructure
   - Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
   - New baghouse, including pulse jet cleaning system and all appurtenances
   - Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
   - One recycle silo with bin vent filter per unit, 8-hour total capacity
   - Two recycle mix tanks per unit
   - Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
   - Agitators for each tank
   - Baghouse ash handling system common to both units
   - Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
   - Pneumatic pressure blowers (8 x 33⅓%)
   - Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
   - Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
   - Includes motors - no spare motor included
   - Cost estimate based on budgetary proposal from Alstom
   - Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

2. <u>FGD Island Foundations and Enclosures</u>
   a. Absorber tower foundations including caissons
   b. Baghouse area foundations including 18" auger cast piles 60' long
   c. Booster fan area foundations

d. 6" insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)

e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas

g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

h. Lime preparation building for Reagent Preparation Area in FGD Island, 50' x 50' x 50', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60' x 60' x 60', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. Reagent Storage and Handling, common to both units:

a. Lime rail car unloader:
- Lime delivery via 25-car unit train
- System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
- Enclosed railcar unloading building
- One vacuum pneumatic system operating to unload a car
- Pneumatic vacuum exhausters (2 x 100%)
- Filter separator with vacuum-to-pressure transfer hopper and valves
- One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack
- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:
- Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
- 32' diameter and 95' height to top
- 1,200-tons storage, each
- Continuous level detection systems
- Bin vent filters
- Live bottom hopper outlets
- Rotary airlock assemblies

- Lime transfer systems:
  - Pressure pneumatic conveying system from lime storage silos to lime day bins
  - Pneumatic pressure blowers (3 x 100%)
  - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. Byproduct Handling System, common to both units

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Continuous level detection system

g. One lot pneumatic conveying piping located on an above grade pipe rack

h. Two truck scales and substructure

i. Existing road improvements for truck haulage to existing landfill

j. Cost estimate based on budgetary proposal from UCC for similar project

k. Concrete foundations including caissons for all material silos

l. Concrete foundations for pneumatic conveying blowers and exhausters

5. Flue Gas Handling System, per unit

a. ID fan outlet to absorber inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6" insulation with lagging

b. Absorber outlet to baghouse inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6" insulation with lagging

c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6" insulation with lagging

d. Concrete foundations for all flue gas ductwork

e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP

   a. Roadwork

   b. Site grading

   c. Soil removal earthwork

   d. Excavation, backfill, and compaction for all foundations

   e. Storm sewer work

   f. Two-cell pond for wastewater storage of process water/slurry

   g. Laydown Area
      - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.

   h. Highway Intersection Upgrade to provide sufficient plant access for construction period
      - New Bypass Lane on Westside of Highway 365
      - New Southbound Left Turn Lane on Highway 365
      - New Northbound Merge Lane on Highway 365
      - New Northbound Right Turn Lane on Highway 365
      - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
      - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
      - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing

   i. New warehouse building 200' x 75' x 15', including substructure and superstructure.

7. Mechanical BOP System

   a. Interconnecting piping, above-ground and buried

   b. Valves for interconnecting piping, above-ground and buried

   c. Lime slaking water storage tank, 115,000-gallon capacity

   d. Slaker water 3" in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
   - Between lime railcar unloading enclosure and lime silos
   - Between lime silos and lime day bins
   - From baghouse hoppers to recycle silos and FGD by-product silo
   - From lime slurry storage tanks to absorber
   - From recycle slurry storage tank to absorber
   - Concrete foundations including caissons for all pipe racks
   - Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
   - Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150' TDH
   - Four reagent prep/recycle sump pumps, 120 gpm @ 150' TDH
   - Two lime silo and unloading area sump pumps, 120 gpm @ 150' TDH
   - Two by-product ash silo area sump pumps, 120 gpm @ 150' TDH
   - Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200' TDH
   - Two lime slaking water pumps, 750 gpm @ 100' TDH
   - One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100' TDH, including new intake structure, piping and valves
   - Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
   - Air compressors; 2 x 100%, 250 scfm each @ 100 psig
   - IA dryers w/filters; 2 x 100%, 250 net scfm each
   - Air receivers; 2 x 100%
   - Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
   - Heat-traced piping

i. Service Air System, common to both units
   - Air compressors; 2 x 100%
   - Air receivers; 2 x 100%

j. Field painting
   - Multiple coat system used for exposed ductwork only
   - Inorganic zinc primer and polyurethane system used for steel
   - Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation
   a. Hazardous material accumulation building
   b. Ash handling maintenance building
   c. Drainage ditch
   d. Pipe trench
   e. Fabrication shop
   f. Existing contractor electrical hook up
   g. Existing drainage ditches, rerouted with new concrete trenches
   h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD
   i. Rail Yard Extension, common to both units
      - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs
   j. Fire Protection System Modifications
      - Deluge system has been included for the new transformers
      - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
      - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System
   a. One 115-kV, 1200A isolation disconnect switch
   b. One startup transformer
   c. Two unit auxiliary transformers (UAT)
   d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)
   e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)
   f. Two 480-V double ended switchgear buses per unit (total of four)
   g. Six 480-V motor control centers per unit (total of twelve)
   h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)
   i. Two isolated phase UAT tap bus extensions
   j. Non-segregated phase bus
   k. Medium-voltage cable
   l. Low voltage, control and instrumentation cable, as necessary
   m. Two electrical equipment buildings

10. Instrumentation and Controls BOP System

   a. Controls System based on an estimated number of I/O points:

      - Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.
      - Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

   b. CEMS, per unit

      - Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

   a. Labor Wage Rates

   Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

   b. Labor crews

   Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

   a. Scaffolding and Consumables
   b. Premiums and per diems ($10 per hour)
   c. Overtime is included based on five 10-hour shifts per week work schedule

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. <u>EPC Indirect Costs</u>

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. <u>Escalation</u>

Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

    Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

   Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

   a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:

      - Project Development (through EPC Award) – 25 months, equivalent of 10 people
      - Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

   b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder's Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. <u>Third Party Services – Construction Management Oversight</u>

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. <u>Third Party Services – Startup and Commissioning Oversight</u>

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

a. Commissioning Support Specialists – 8 months, 2 people

The total cost of the startup and commissioning s upport was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

   The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

   The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

   a. Conceptual Study Support
   b. EPC Specification Supporting Documents
   c. Project Schedule Development
   d. EPC Specification Development
   e. EPC Bid Evaluation and Contract Conformance
   f. General Project Support
      - Monthly Project Status Meetings
      - Weekly Teleconferences
      - Overall Coordination
      - Project Administration
      - Site Visits and Travel
   g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
   h. Design Review of Drawing Submittals
   i. Technical support during design, fabrication, construction, commissioning, and testing
   j. Equipment vendor QA/QC audits

   The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

   The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

   a. Development of the test protocol
   b. Procuring the services of the testing contractor
   c. Overseeing the performance test campaign
   d. Evaluating the results of the testing with respect to guarantee compliance

   The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

   The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.
b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.
c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost	$/MWh	$43.35

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Design 0.68 lb SO_2/MMBtu
Dry FGD System Parameters		
Reagent Consumption	lb/hr	7,000
Byproduct Waste Production	lb/hr	16,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	75
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,888,000
Byproduct Waste Disposal Cost	$/year	$380,000
Aux Power Cost	$/year	$3,027,000
Water Cost	$/year	$214,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,881,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.46%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Design 0.68 lb SO_2/MMBtu
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.68 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.68 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses, and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	Design Capacity @ 1.2 lb/MMBtu	Design Capacity @ 0.68 lb/MMBtu	Cost Reduction for 1.2 to 0.68 lb/MMBtu[1]
Two long-term storage silos	2,200 tons each	1,200 tons each	- $4,332,000
Two lime day bins	650 tons each	300 tons each	- $272,000

Two detention lime slakers	13 tons/hour each	7 tons/hour each	- $113,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $373,000
Two FGD by-product storage silos	3,000 tons each	1,750 tons each	- $2,400,000
		TOTAL Differential	**- $7,490,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.68 lb SO_2/MMBtu is approximately $7.5M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A
2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A
3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule
4. Monthly Progress Payment Schedule for White Bluff DFGD Project
5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates
6. S&L Estimating Documentation: Escalation Projections
7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing
8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	06/29/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387A
Cost index	ARPBL

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Project Cost Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	104,382,058		1,309,072
Material	64,284,799		
Subcontract	313,285,100		
Process Equipment	23,517,000		
	505,468,957	505,468,957	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	7,306,743		
91-2 Cost Due To OT 5-10's	14,545,500		
91-4 Per Diem	13,090,700		
91-5 Consumables	1,043,800		
91-6 Freight on Material	3,214,200		
91-8 Sales Tax	8,928,800		
91-9 Contractors G&A	20,987,700		
91-10 Contractors Profit	10,493,800		
	79,611,243	585,080,200	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	60,898,000		
	84,798,000	669,878,200	
Escalation:			
96-1 Escalation on Material	7,632,000		
96-2 Escalation on Labor	23,480,200		
96-3 Escalation on Subcontract	37,428,800		
96-4 Escalation on Process Eq	2,158,600		
96-5 Escalation on Indirects	12,334,500		
	83,034,100	752,912,300	
Total EPC Cost		***752,912,300***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	811,458,300	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	824,002,300	
Project Contingency :			
110 Project Contingency	111,145,700		
	111,145,700	935,148,000	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	937,421,000	
Interest During Construction:			
130 Interest During Constr.	134,949,000		
	134,949,000	1,072,370,000	
Total		***1,072,370,000***	

Exhibit B to EAI Comments

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,814	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,162,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	1,089,675	107,800	7,935,771	23,610,546
111	FLUE GAS SYSTEM		480,000	16,910,288	337,269	29,197,085	46,587,373
121	CIVIL BOP	570,000		8,073,474	106,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,969,000	6,882,913	115,659	9,189,021	19,038,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,665,684	290,576	20,231,688	43,196,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,884	841,993	3,424,993
	TOTAL DIRECT	**313,285,100**	**23,517,000**	**64,284,799**	**1,309,072**	**104,382,058**	**505,468,956**

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU. Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

Estimate No.: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			**FGD ISLAND**									
	23.00.00		STEEL									
		23.13.75	SILO									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				(273,000)		-690		(50,428)	(323,428)
			STEEL				(273,000)		-690		(50,428)	(323,428)
	31.00.00		MECHANICAL EQUIPMENT									
		31.45.00	FGD EQUIPMENT									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
			MECHANICAL EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			10 FGD ISLAND			**297,904,000**	**(1,649,000)**		**-7,814**		**(680,533)**	**295,574,467**
101			**FGD ISLAND FOUNDATIONS AND ENCLOSURES**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					961,632	13,324		1,445,136	2,406,768
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					1,043,634	14,211		1,541,379	2,585,013

Estimate No..: 33387A
Project No.: 13027-002
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Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					2,005,266	27,536		2,986,515	4,991,781
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					1,938,900	67,828		4,049,985	5,988,885
			CONCRETE					1,938,900	67,828		4,049,985	5,988,885
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					1,204,900	11,798		779,520	1,984,420
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					5,402,720	38,437		3,560,015	8,962,735
			STEEL					6,607,620	50,235		4,339,534	10,947,154
	24.00.00		ARCHITECTURAL									
		24.17.00	ELEVATOR									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

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ENTERGY ARKANSAS
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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					318,700	1,885		199,892	518,592
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					30,000	230		21,292	51,292
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					157,289	2,782		97,436	254,725
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					655,963	5,473		435,626	1,091,589
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		30,358	353,358
			ARCHITECTURAL					1,484,952	10,794		784,604	2,269,556
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					86,900	1,217		83,325	170,225
		31.83.00	TANK									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						345		31,314	31,314
			MECHANICAL EQUIPMENT					86,900	1,562		114,639	201,539
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					173,800	182		11,641	185,441
			HVAC					173,800	182		11,641	185,441
	36.00.00		INSULATION									
		36.13.00	DUCT									

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		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					2,367,390	96,576		6,640,559	9,007,949
			INSULATION					2,367,390	96,576		6,640,559	9,007,949
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					173,800	182		11,556	185,356
			ELECTRICAL EQUIPMENT					173,800	182		11,556	185,356
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					**14,838,628**	**254,893**		**18,939,033**	**33,777,661**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					120,204	1,666		180,642	300,846
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					185,700	2,529		274,267	459,967
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					1,914,200	23,609		1,918,719	3,832,919
			CIVIL WORK					2,220,104	27,803		2,373,628	4,593,732
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					350,750	12,270		732,649	1,083,399
			CONCRETE					350,750	12,270		732,649	1,083,399
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					525,000	4,828		447,131	972,131
			ARCHITECTURAL					525,000	4,828		447,131	972,131
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 LS	6,000,000				59.71 /MH		6,000,000

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		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			**6,000,000**	**2,046,000**	**3,162,954**	**59,192**		**4,646,650**	**15,855,604**
105			**BYPRODUCT HANDLING SYSTEM**									

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	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					232,125	3,161		342,833	574,958
			CIVIL WORK					232,125	3,161		342,833	574,958
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					212,750	7,443		444,393	657,143
			CONCRETE					212,750	7,443		444,393	657,143
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				275,000		2,839		207,594	482,594
			STEEL				275,000		2,839		207,594	482,594
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		83,587		6,111,857	12,446,857
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				182,000		460		31,485	213,485
			MATERIAL HANDLING EQUIPMENT				6,517,000		84,046		6,143,342	12,660,342
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			113,100						113,100
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SIL	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Exhibit B to EAI Comments

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ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			**7,713,100**	**6,872,000**	**1,089,675**	**107,800**		**7,935,771**	**23,610,546**
111			**FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			DUCTWORK					5,638,100	119,641		11,635,124	17,273,224
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			GIRDER					7,089,360	90,207		8,354,963	15,444,323
			STEEL					12,727,460	209,848		19,990,087	32,717,547
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES				480,000		2,943		286,161	766,161
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT					915,000	10,517		1,022,802	1,937,802
			MECHANICAL EQUIPMENT				480,000	915,000	13,460		1,308,963	2,703,963
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691

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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			111 FLUE GAS SYSTEM				**480,000**	**16,910,288**	**337,269**		**29,197,085**	**46,587,373**
121			**CIVIL BOP**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						28,506		5,197,453	5,197,453
		21.17.00	EXCAVATION									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						4,868		439,945	439,945
		21.19.00	DISPOSAL									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						483		38,288	38,288
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						172		13,674	13,674
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					110,000	2,299		165,839	275,839
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					1,065,011	3,448		335,555	1,400,566
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					3,346,203	19,569		1,533,638	4,879,841
		21.71.00	TRACKWORK									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			220,000						220,000
		21.99.00	CIVIL WORK, MISCELLANEOUS									

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CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287
			CIVIL WORK, MISCELLANEOUS					780,000	9,195		729,287	1,509,287
			CIVIL WORK			220,000		5,301,214	68,540		8,453,679	13,974,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					362,280	7,703		459,973	822,253
		22.15.00	EMBEDMENT									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					30,000	575		29,368	59,368
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					27,500	2,529		206,370	233,870
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					138,375	2,793		157,391	295,766
			CONCRETE					558,155	13,600		853,102	1,411,257
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					486,700	6,768		626,888	1,113,588
		24.41.00	SIDING									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					13,788	132		10,511	24,299
			ARCHITECTURAL					500,488	6,900		637,400	1,137,888
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.99.00	MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					1,110,000	15,537		1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM					1,110,000	15,537		1,439,017	2,549,017
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					15,000	172		8,209	23,209
			PAINTING & COATING					15,000	172		8,209	23,209

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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					93,638	1,311		89,786	183,423
			MECHANICAL EQUIPMENT					93,638	1,311		89,786	183,423
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					187,275	196		12,544	199,819
			HVAC					187,275	196		12,544	199,819
	36.00.00		INSULATION									
		36.99.00	INSULATION, MISCELLANEOUS									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					20,430	196		10,000	30,430
			INSULATION					20,430	196		10,000	30,430
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					187,275	196		12,452	199,727
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					100,000	230		18,862	118,862
			ELECTRICAL EQUIPMENT					287,275	426		31,314	318,589
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			350,000						350,000
			PROJECT INDIRECT			350,000						350,000
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						517		41,022	41,022
			DEMOLITION						517		41,022	41,022
	21.00.00		CIVIL WORK									
		21.17.00	EXCAVATION									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,575	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		[illegible]	-	-	9,929	539	79.31 /MH	42,754	52,684

Exhibit B to EAI Comments

Estimate No..: 33387A
Project No.: 13027-002
Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					156,460	8,154		646,677	803,138
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					690,804	9,407		1,020,272	1,711,076
			CIVIL WORK					847,264	17,561		1,666,949	2,514,214
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					94,530	3,307		197,455	291,985
			CONCRETE					94,530	3,307		197,455	291,985
	23.00.00		STEEL									
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					653,110	4,709		436,166	1,089,276
			STEEL					653,110	4,709		436,166	1,089,276
	27.00.00		PAINTING & COATING									
		27.13.00	COATING									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			270,000						270,000
			PAINTING & COATING			270,000						270,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.17.00	COMPRESSOR & ACCESSORIES									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				709,200		405		27,707	736,907
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					127,500	1,959		151,519	279,019
		31.65.00	HEAT EXCHANGER									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				220,000		368		23,404	243,404

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	PUMP									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE- RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				1,039,800		3,998		273,763	1,313,563
		31.83.00	TANK									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			728,000						728,000
			MECHANICAL EQUIPMENT			728,000	1,969,000	127,500	6,729		476,392	3,300,892
	35.00.00		PIPING									
		35.13.01	SS 304, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					198,156	7,494		579,755	777,911
		35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					609,874	36,441		2,819,087	3,428,961
		35.13.36	DUCTILE IRON, ABOVE GROUND, PROCESS AREA									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					162,000	3,594		259,256	421,256
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					127,845	4,471		345,897	473,742
		35.15.10	CARBON STEEL, BURIED									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565

Estimate No.: 33387A
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Estimate Date: 06/29/2015
Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	CARBON STEEL, BURIED									
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					912,807	19,533		1,511,045	2,423,852
		35.15.25	FRP, BURIED									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					50,024	1,554		120,219	170,243
		35.15.30	HDPE, BURIED									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					33,640	2,413		186,633	220,273
		35.36.00	PIPE SUPPORTS, RACK									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					81,550	1,071		82,873	164,423
		35.45.00	VALVES									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					2,860,785	4,228		327,099	3,187,884
			PIPING					5,036,681	80,799		6,231,866	11,268,547
	36.00.00		INSULATION									
		36.17.01	PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					47,494	1,860		127,914	175,408
			INSULATION					47,494	1,860		127,914	175,408
	41.00.00		ELECTRICAL EQUIPMENT									
		41.33.00	HEAT TRACING									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					76,334	177		11,256	87,590
			ELECTRICAL EQUIPMENT					76,334	177		11,256	87,590

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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			151 MECHANICAL BOP			**998,000**	**1,969,000**	**6,882,913**	**115,659**		**9,189,021**	**19,038,934**
190			**DEMOLITION / RELOCATION**									
	11.00.00		DEMOLITION									
		11.21.00	CIVIL WORK									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						2,732		222,400	222,400
		11.22.00	CONCRETE									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						1,049		112,307	112,307
		11.23.00	STEEL									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						359		38,408	38,408
		11.24.00	ARCHITECTURAL									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						1,801		192,854	192,854
		11.31.00	MECHANICAL EQUIPMENT									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						290		26,852	26,852
		11.35.00	PIPING									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						162		17,401	17,401
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						2,299		212,920	212,920
			DEMOLITION						8,691		823,142	823,142
	21.00.00		CIVIL WORK									
		21.16.00	GENERAL EARTHWORK									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK				100,800	856		156,133	256,933

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		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,200	3,902		353,060	788,260
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									

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		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695
			GIRDER					3,415	25		2,280	5,695
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELECBLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					15,752	1,491		138,057	153,809
			STEEL					134,731	2,873		230,077	364,808
	24.00.00		ARCHITECTURAL									
		24.15.00	DOOR (INCL. FRAME & HARDWARE)									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					5,000	92		4,699	9,699
		24.27.00	MASONRY									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					4,242	106		5,601	9,842
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					140,000	1,954		180,982	320,982
		24.37.00	ROOFING									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					50,505	2,241		78,493	128,998
		24.41.00	SIDING									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					140,760	870		69,207	209,967
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					105,000	2,391		122,170	227,170
			ARCHITECTURAL					445,507	7,653		461,151	906,658
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18'TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					2,025	23		1,108	3,133
			PAINTING & COATING					2,025	23		1,108	3,133
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						657		57,565	57,565
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									

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		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					37,500	523		35,814	73,314
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					80,000	575		39,356	119,356
			MECHANICAL EQUIPMENT					117,500	1,755		132,736	250,236
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS- HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS- HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					46,200	48		3,094	49,294
			HVAC					46,200	48		3,094	49,294
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					1,806	45		3,518	5,323
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					12,660	400		30,944	43,604
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					6,913	191		14,761	21,674
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					160	66		5,122	5,282
			PIPING					21,539	702		54,344	75,883
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					126,500	132		8,411	134,911
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					14,700	55		3,511	18,211
			ELECTRICAL EQUIPMENT					141,200	187		11,921	153,121
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					258	4		266	524

Estimate No.: 33387A
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Prep/Rev/App: A. KOCI/BA/MNO

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			**100,000**		**1,578,182**	**33,735**		**2,546,302**	**4,224,484**
201			**ELECTRICAL BOP SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									

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ENTERGY ARKANSAS
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CONCEPTUAL COST ESTIMATE

Sargent & Lundy

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					764,220	5,510		510,368	1,274,588
			STEEL					764,220	5,510		510,368	1,274,588
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				1,008,000		10,023		546,536	1,554,536
			ARCHITECTURAL				1,008,000		10,023		546,536	1,554,536
	41.00.00		ELECTRICAL EQUIPMENT									
		41.13.00	BUS DUCT									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				903,000		10,345		658,241	1,561,241
		41.45.00	MOTOR CONTROL CENTER (MCC), COMPLETE									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				636,000		5,931		377,392	1,013,392
		41.51.00	POWER TRANSFORMER									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				3,520,000		5,402		343,748	3,863,748
		41.55.00	SWITCHGEAR, COMPLETE									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				3,392,000		26,638		1,694,972	5,086,972
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				2,840,000		11,494		731,379	3,571,379
			ELECTRICAL EQUIPMENT				11,291,000		59,810		3,805,732	15,096,732
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.13.00	CABLE TRAY									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					505,000	33,333		2,059,667	2,564,667
		42.15.37	CONDUIT, RGS									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					90,000	74,138		4,580,983	4,670,983
		42.18.00	DUCT BANK									

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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	DUCT BANK									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					595,000	107,471		6,640,649	7,235,649
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					645,120	18,538		1,521,037	2,166,157
		43.20.00	600V CABLE & TERMINATION									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					1,881,340	30,069		2,467,159	4,348,499
		43.40.00	5/8KV CABLE & TERMINATION									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					5,713,230	33,903		2,781,778	8,495,008
		43.50.00	15KV CABLE & TERMINATION									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					206,721	5,895		483,718	690,439
			CABLE					8,446,411	88,406		7,253,692	15,700,103
	51.00.00		SUBSTATION, SWITCHYARD & TRANSMISSION LINE									
		51.15.27	CIRCUIT BREAKER									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	DISCONNECT SWITCH									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS, INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					15,000	69		3,847	18,847
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					15,000	69		3,847	18,847
			201 ELECTRICAL BOP SYSTEM				**12,299,000**	**10,665,684**	**290,576**		**20,231,688**	**43,196,372**
211			INSTRUMENTATION AND CONTROLS BOP SYSTEM									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.13.00	CONTROL SYSTEM									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				1,500,000		2,299		148,690	1,648,690
		44.21.00	INSTRUMENT									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					578,000	7,946		651,967	1,229,967
		44.25.00	MONITORING EQUIPMENT									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS BOP SYSTEM				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow

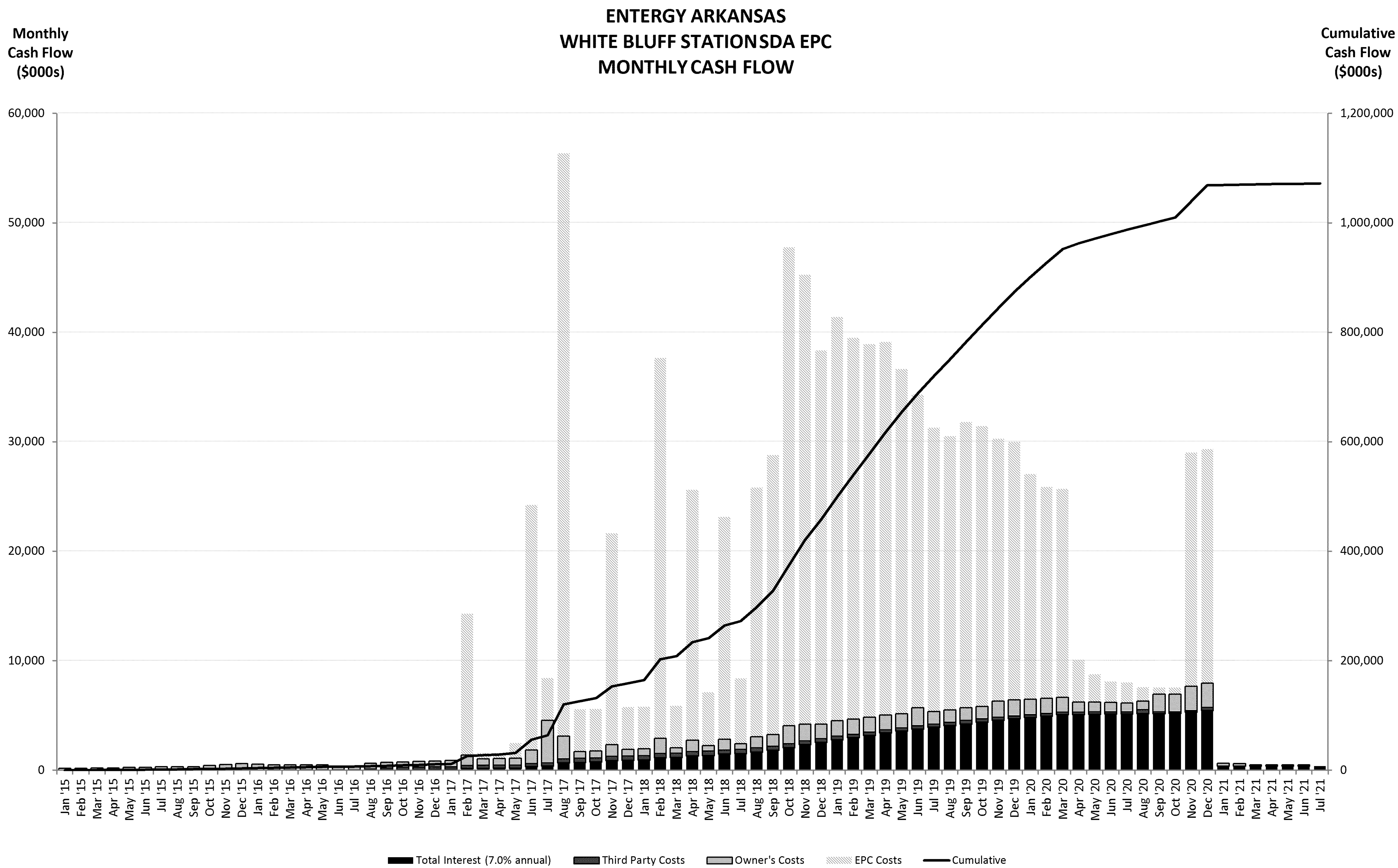


Exhibit B to EAI Comments

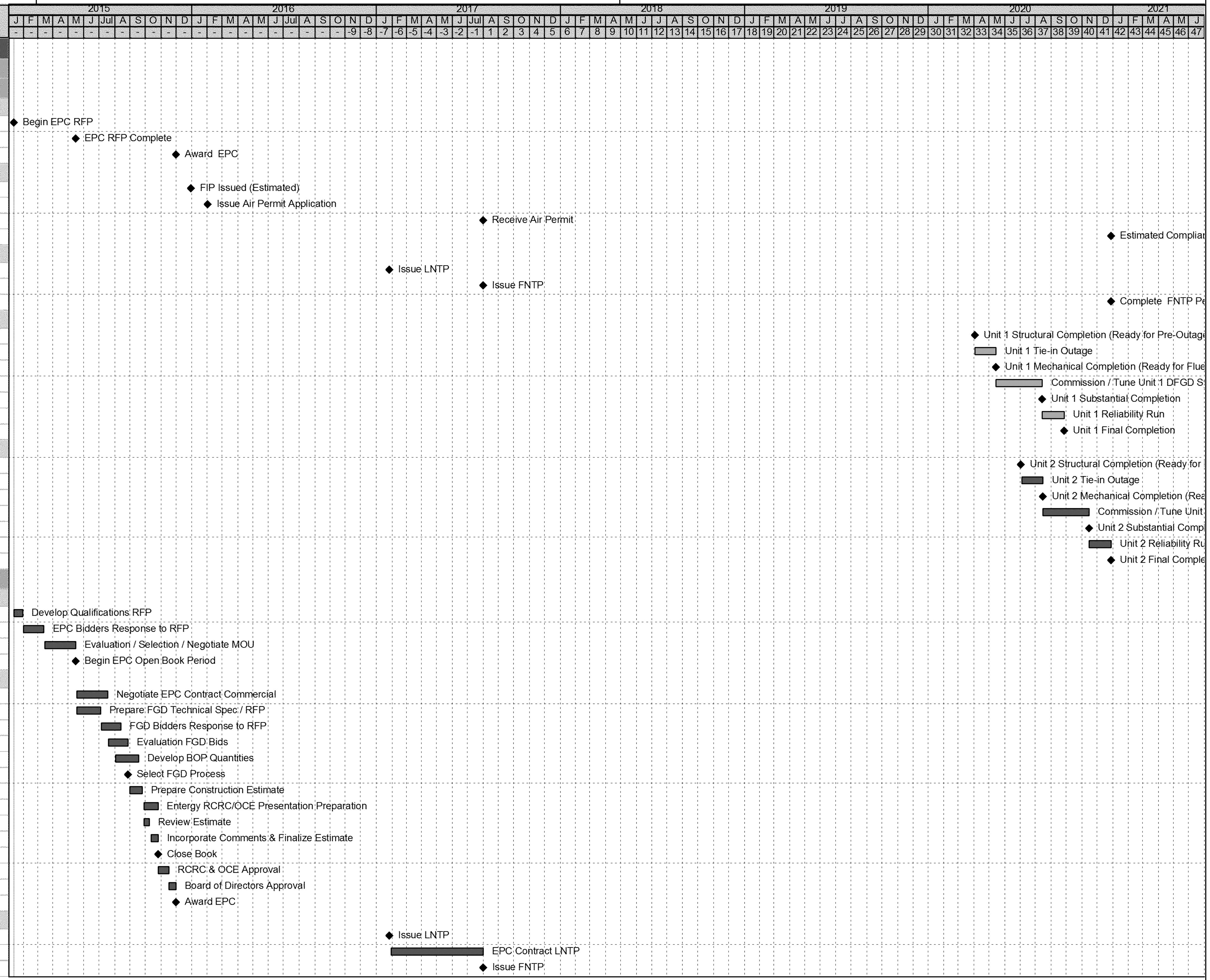
ATTACHMENT 3

Level 1 Preliminary Execution Schedule

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17



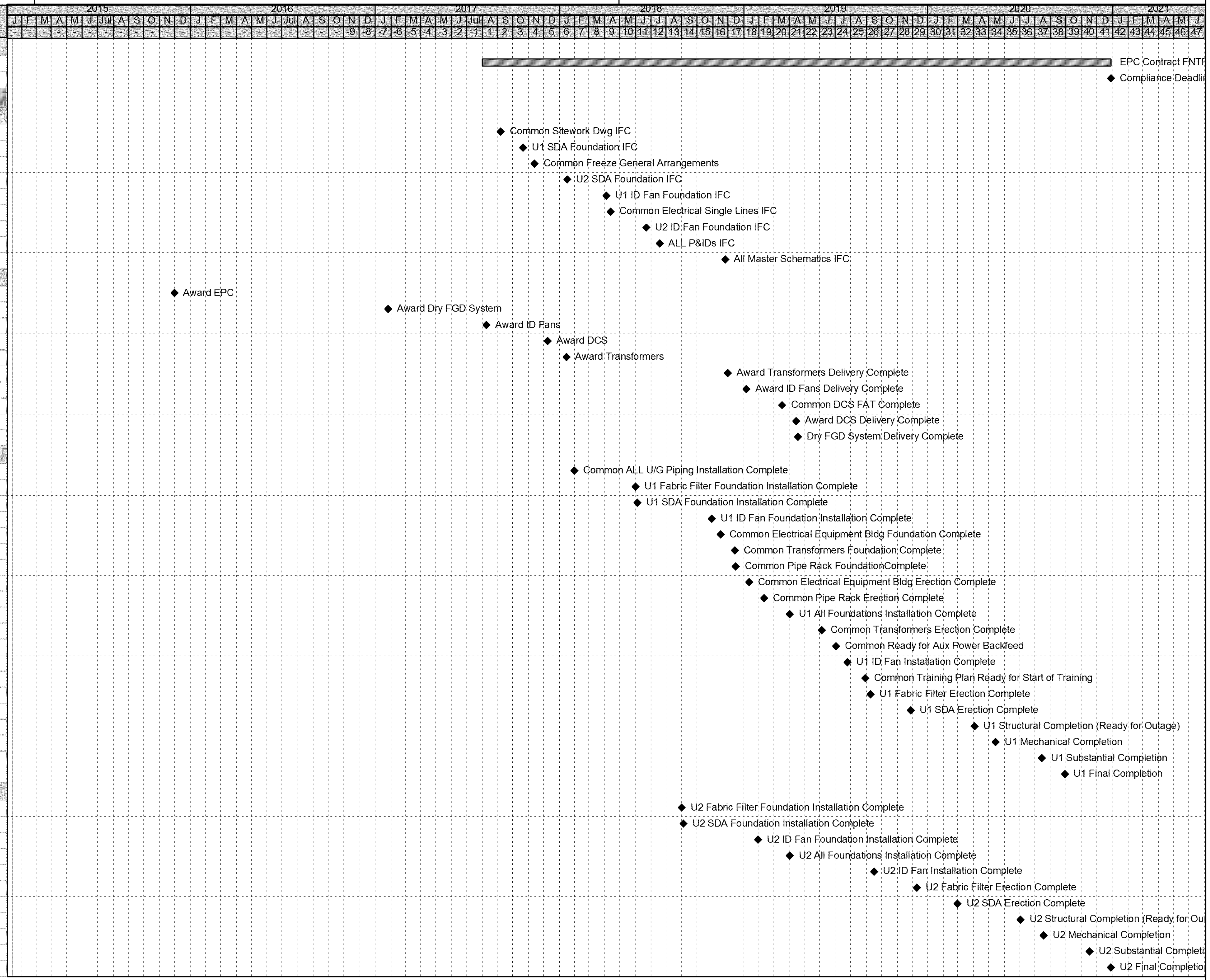
Remaining Work — Actual Work — WBS Summary
Critical Remaining Work — Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020) 29-May-15 15:26

Activity ID	Activity Name	Orig Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20



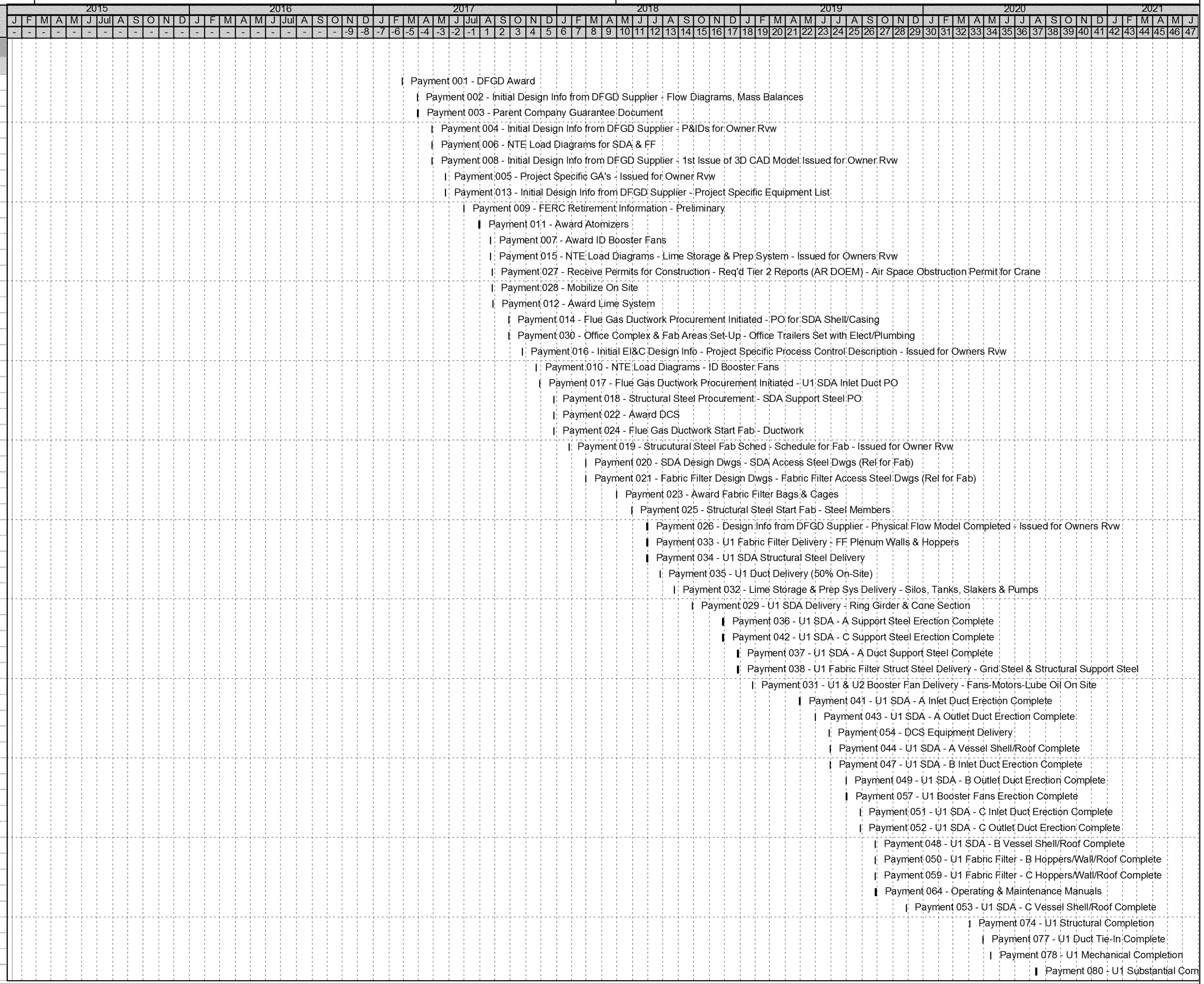
Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020) | 29-May-15 15:26

Activity ID	Activity Name	Orig Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20



Remaining Work | Actual Work | WBS Summary
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TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Orig Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18

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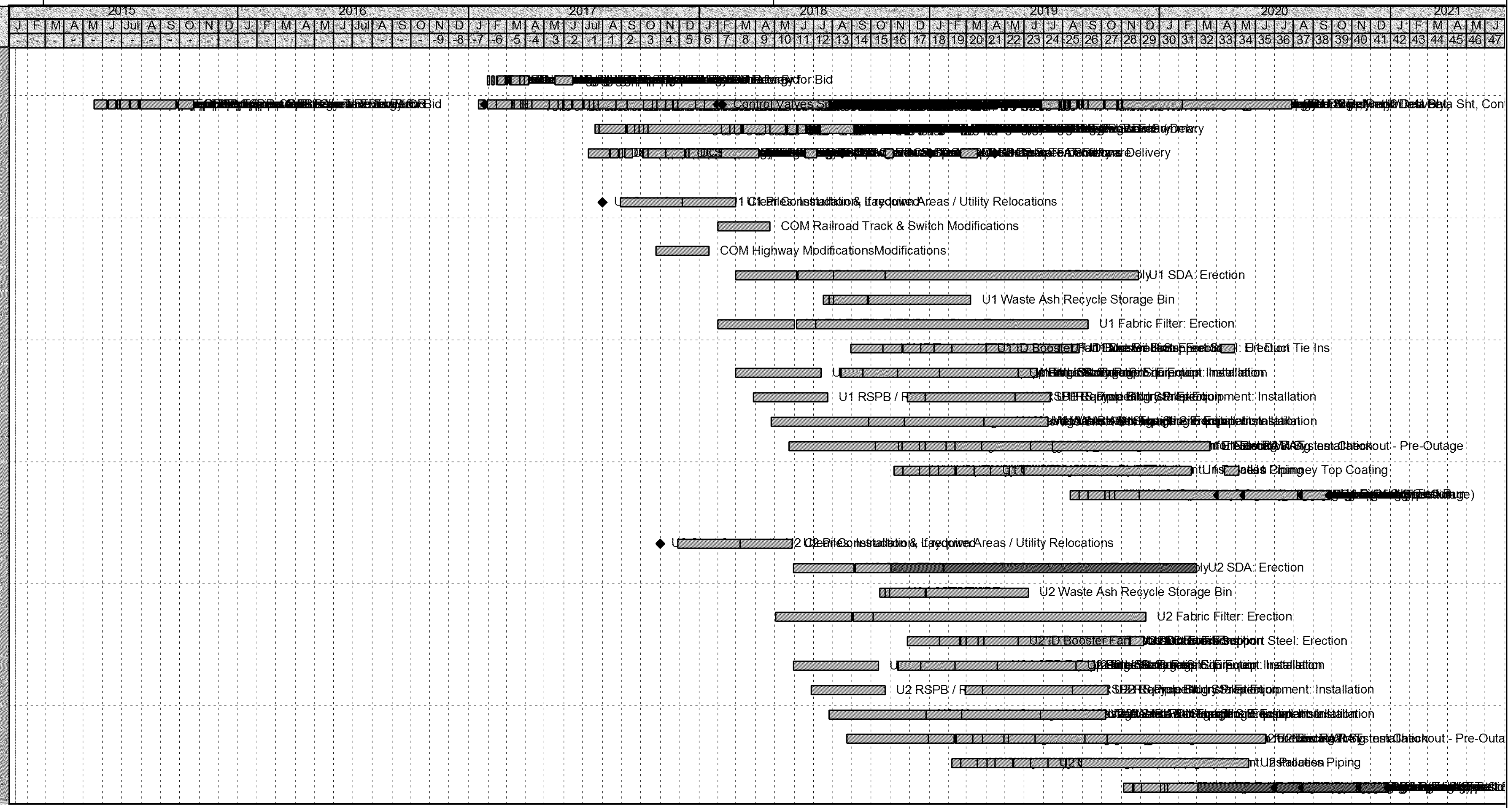
TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

WHITE BLUFF FGD SCHEDULE (December 2020)

29-May-15 15:26

Activity ID	Activity Name	Ori Dur	Start	Finish
	Procurement	1357	18-May-15	28-Jul-20
	C/S/A Procurement	98	30-Jan-17	15-Jun-17
	Mechanical Procurement	1357	18-May-15	28-Jul-20
	Electrical Procurement	347	20-Jul-17	30-Nov-18
	I&C Procurement	448	10-Jul-17	15-Apr-19
	U1 Construction	720	02-Aug-17	05-May-20
	U1 Sitework	150	02-Aug-17	27-Feb-18
	U1 Railroad Track & Switch Mods	60	31-Jan-18	24-Apr-18
	U1 Highway Mods	60	25-Oct-17	16-Jan-18
	U1 SDA	457	28-Feb-18	28-Nov-19
	U1 Field Fabricated Tanks	170	16-Jul-18	08-Mar-19
	U1 Fabric Filter	419	31-Jan-18	09-Sep-19
	U1 ID Booster Fans / Ductwork	436	29-Aug-18	29-Apr-20
	U1 Lime Slurry	343	28-Feb-18	21-Jun-19
	U1 Recycle Slurry	337	29-Mar-18	12-Jul-19
	U1 Byproduct Handling	314	25-Apr-18	08-Jul-19
	U1 Auxiliary Power	478	23-May-18	20-Mar-20
	U1 Balance of Plant	390	07-Nov-18	05-May-20
	U1 System Testing and Commissioning	294	13-Aug-19	27-Sep-20
	U2 Construction	686	01-Nov-17	17-Jun-20
	U2 Sitework	150	01-Nov-17	29-May-18
	U2 SDA	458	30-May-18	28-Feb-20
	U2 Field Fabricated Tanks	170	15-Oct-18	07-Jun-19
	U2 Fabric Filter	419	02-May-18	09-Dec-19
	U2 ID Booster Fans / Ductwork	268	28-Nov-18	07-Dec-19
	U2 Lime Slurry	343	30-May-18	20-Sep-19
	U2 Recycle Slurry	337	28-Jun-18	11-Oct-19
	U2 Byproduct Handling	314	25-Jul-18	07-Oct-19
	U2 Auxiliary Power	476	22-Aug-18	17-Jun-20
	U2 Balance of Plant	337	06-Feb-19	21-May-20
	U2 System Testing and Commissioning	301	05-Nov-19	29-Dec-20



Remaining Work
Actual Work
WBS Summary
Critical Remaining Work
Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

ATTACHMENT 4

Milestone Progress Payment Schedule

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings NTE Load Diagrams	0.16	1.79
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model Award Booster Fans	2.62	4.41
6	Jul-17	NTE Load Diagrams Award Atomizers	0.45	4.86
7	Aug-17	DFGD Supplier - Equipment Lists Award Lime System	6.24	11.10
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information NTE Load Diagrams	0.45	12.00
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication	2.68	22.36
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery Office Complex and Fabrication Areas Set-Up	2.99	31.67
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery Lime Storage and Preparation System Delivery Unit 1 Fabric Filter Delivery	5.12	36.79
22	Nov-18	Unit 1 SDA Structural Steel Delivery Unit 1 Duct Delivery Unit 1 SDA-A Support Steel Erection Complete	4.81	41.60
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete Unit 1 Fabric Filter Structural Steel Delivery Unit 2 Duct Delivery	4.00	45.60
24	Jan-19	Unit 2 SDA Delivery Unit 1 SDA-A Inlet Duct Erection Complete Unit 1 SDA-C Support Steel Erection Complete	4.32	49.92
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete Unit 1 SDA-A Vessel Shell/Roof Complete Unit 2 Fabric Filter Delivery	4.08	54.00
26	Mar-19	Unit 2 Structural Steel Delivery Unit 1 SDA-B Inlet Duct Erection Complete Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete	3.99	57.99

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

Entergy
White Bluff DGFD Project
Escalation Projections

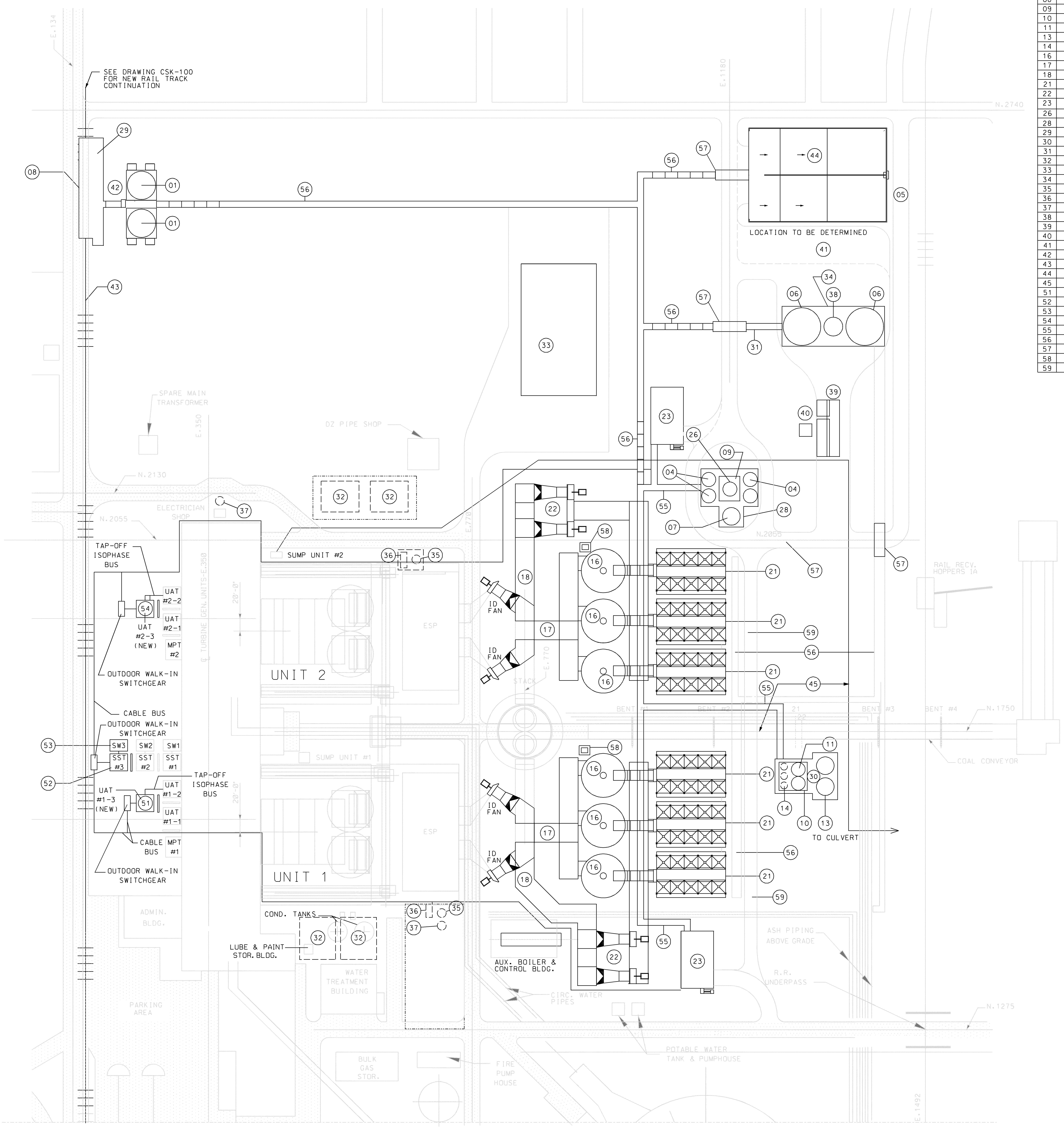
Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

Misc Material and Equipment (Please see Note 1)	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index	8%	15%	17.00%
Material Price, Construction Mat.	8%	7%	10.00%
Plant Cost Index	no increase	slightly negative	5.00%
Civil Work	8%	14%	15.00%
Steel - ductwork	no increase	slightly negative	8.00%
Steel - rolled shape	8%	no increase	10.00%
Architectural	5%	4%	8.00%
Overall mechanical equipment	4%	1%	7.00%
Overall piping	6%	11%	12.00%
Overall electrical equipment	9%	17%	18.00%
Raceway, Cable Tray, & Conduit	8%	slightly negative	10.00%
Electrical cable	14%	7%	15.00%
Controls & Instrumentation	1%	1%	5.00%
Average overall increase for Power back-fit projects	**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

ATTACHMENT 7

Conceptual General Arrangement Drawing



LEGEND	
01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE

HOLD INFORMATION

NO.	DATE	DESCRIPTION
△		

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: -

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

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CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

DRAWING NUMBER	REVISION
M-GA-001	N/A

SHEET 1 OF 1

PRELIMINARY
NOT FOR
CONSTRUCTION

NORTH

60' 0 60' 120' 180'
GRAPHIC SCALE

DRAWING SCALE
1" = 60'-0"

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ATTACHMENT 8

Entergy Basis of Contingency

WB FGD Project

Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	**$ 740,968,200**				
	P90	**P80**	**P70**	**P60**	**P50**
Risk Contingency	**$ 35,870,000**	**$ 27,220,000**	**$ 20,550,000**	**$ 16,210,000**	**$ 13,090,000**
Estimate Uncertainty Contingency	**$ 95,350,000**	**$ 66,600,000**	**$ 41,540,000**	**$ 21,330,000**	**$ (290,000)**
Unknown Risk Contingency	**$ 18,560,000**	**$ 17,380,000**	**$ 16,450,000**	**$ 15,610,000**	**$ 14,810,000**
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			**Resulting Range**	
Estimate class	**Maturity level of project definition** **expressed as % of complete engineering**	**End usage** **typical purpose of estimate**	**Methodology** **typical estimating method**	**Estimate accuracy range** **typical variation in low & high ranges**	**Target contingency range**
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

WB FGD Project
Risk Register

ESTIMATE UNCERTAINTY

Risk Category	Description of Risk	Quantitative Risk Analysis: Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

WB FGD Project

Risk Register

UNKNOWN RISK							
		Quantitative Risk Analysis					
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

WB FGD Project
Risk Register

IDENTIFIED RISKS																	
				SCORING							Quantitative Risk Analysis						
Risk ID	**Risk Category**	**Description of Risk**	**Unit**	**Prob. Rating & History**	**Cost Impact Rating**	**Schedule Impact Rating**	**Other Impact Rating**	**Total Risk Score**	**Risk Rating**	**Justification of Ratings**	**Probability**	**Min ($)**	**Expected**	**Max ($)**	**Include in QRA**	**QRA Comments**	**Status / Comments**
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

WB FGD Project
Risk Register

				SCORING							Quantitative Risk Analysis						
Risk ID	Risk Category	Description of Risk	Unit	Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

WB FGD Project

Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	[redacted]	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	[redacted]	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	[redacted]	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	[redacted]	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	[redacted]	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

WB FGD Project
Risk Register

				SCORING							Quantitative Risk Analysis						
Risk ID	**Risk Category**	**Description of Risk**	**Unit**	**Prob. Rating & History**	**Cost Impact Rating**	**Schedule Impact Rating**	**Other Impact Rating**	**Total Risk Score**	**Risk Rating**	**Justification of Ratings**	**Probability**	**Min ($)**	**Expected**	**Max ($)**	**Include in QRA**	**QRA Comments**	**Status / Comments**
2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

WB FGD Project
Risk Register

				SCORING							Quantitative Risk Analysis						
Risk ID	Risk Category	Description of Risk	Unit	Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project
Risk Register

				SCORING							Quantitative Risk Analysis						
Risk ID	**Risk Category**	**Description of Risk**	**Unit**	**Prob. Rating & History**	**Cost Impact Rating**	**Schedule Impact Rating**	**Other Impact Rating**	**Total Risk Score**	**Risk Rating**	**Justification of Ratings**	**Probability**	**Min ($)**	**Expected**	**Max ($)**	**Include in QRA**	**QRA Comments**	**Status / Comments**
2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

WB FGD Project
Risk Register

				SCORING							Quantitative Risk Analysis						
Risk ID	**Risk Category**	**Description of Risk**	**Unit**	**Prob. Rating & History**	**Cost Impact Rating**	**Schedule Impact Rating**	**Other Impact Rating**	**Total Risk Score**	**Risk Rating**	**Justification of Ratings**	**Probability**	**Min ($)**	**Expected**	**Max ($)**	**Include in QRA**	**QRA Comments**	**Status / Comments**
2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project
Risk Register

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

REGIONAL HAZE MODELING ASSESSMENT REPORT

Entergy Arkansas, Inc. > Independence Plant

Entergy
THE POWER OF PEOPLE℠

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August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit C to EAI Comments

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published a proposed Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the proposed Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) that the EPA disapproved in its final action, published March 12, 2012.[1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) for Class I areas in Arkansas and reasonable progress control requirements to achieve these RPGs. Specifically, the EPA proposed to meet RPGs by presenting two options for controlling emissions from the Entergy Arkansas, Inc. (Entergy) Independence Plant, which is not subject to BART.

In order to assess the reasonableness of the proposed control options for Electric Generating Units (EGUs) 1 and 2 at the Entergy Independence Plant (Independence units), as well as the EGUs at Entergy's White Bluff Plant (White Bluff units), the Comprehensive Air Quality Model with Extensions (CAMx) was used to perform regional haze modeling. This analysis was based on the CAMx regional haze modeling originally performed by the Central Regional Air Planning Association (CENRAP).

This report has been prepared to describe the modeling methodology used to evaluate Entergy's proposed control measures for emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) from the Independence and White Bluff units, as alternatives to the EPA's proposed control options. Entergy proposes a comprehensive approach to regional haze, involving the installation of low NO_X burners (LNB) and separated overfire air (SOFA) and a reduction in permitted SO_2 emission rates for the Independence units and White Bluff units, and the cessation of coal combustion at White Bluff by 2028. In addition to Entergy's proposed control scenario, the controls proposed in the Arkansas FIP were also evaluated using CAMx so that the expected visibility improvements from each scenario could be compared to EPA's proposed controls. The modeling methodology was developed in accordance with the original CENRAP modeling and takes into account Arkansas's two Class I areas, the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. REGIONAL HAZE MODELING METHODOLOGY

The regional haze assessment involves the determination of the total light extinction, the contribution of each selected emissions source to the total light extinction, and an analysis of the uniform rate of progress (URP) curves for Caney Creek and Upper Buffalo. This regional haze modeling analysis was performed using the advanced photochemical modeling software CAMx. The CAMx modeling system is a publicly available computer modeling system for the integrated assessment of photochemical and particulate air pollution. A description of the modeling files, domain, model simulation steps, and analysis methodologies are discussed in detail in the following subsections.

2.1. EPA PHOTOCHEMICAL MODELING PLATFORM

This analysis builds on the modeling of 2002 and 2018 emissions conducted previously by CENRAP and subsequently updated by ENVIRON for the EPA to aid in the development of the EPA's proposed Oklahoma and Texas Regional Haze FIP.[2] ENVIRON's 2018 baseline scenario is based on input data originally developed by CENRAP and enhanced by ENVIRON to provide higher resolution results and to accommodate more recent versions of CAMx and associated pre-processors. 2018 emissions data used in this baseline scenario were projected with growth and control factors from the 2002 emissions data obtained from the 2002 National Emissions Inventory (NEI).[3]

2.1.1. Modeling Domain

Figure 2-1 below presents the modeling domain used in the CENRAP regional haze assessment. This nested grid configuration of the CAMx domain includes the following grids:

- RPO_36km: This grid contains 36 kilometer (km) grid cells covering all of the continental U.S., along with southern Canada, northern Mexico, and portions of the Gulf of Mexico, Atlantic Ocean, and Pacific Ocean.
- Regional_12km: This nested grid contains 12 km grid cells covering all of Texas, Arkansas, and Louisiana, a majority of Oklahoma, and parts of Mississippi, Tennessee, Missouri, and New Mexico.

All modeling domain grids are projected in the Lambert Conformal Conic (LCC) map projection. The 36 km grid is also the domain used by the Regional Planning Organizations (RPOs) of which CENRAP is an example. The 12 km grid was developed by ENVIRON to allow for minimizing the effects of the boundary conditions on the 12 km grid since the boundary condition information is passed from the 36 km to the 12 km grid. The modeling domain contains locations of Interagency Monitoring of Protected Visual Environments (IMPROVE) sites which correspond to the Arkansas Class I areas, Caney Creek and Upper Buffalo, which are under consideration in the assessment of RPGs in the Arkansas FIP.

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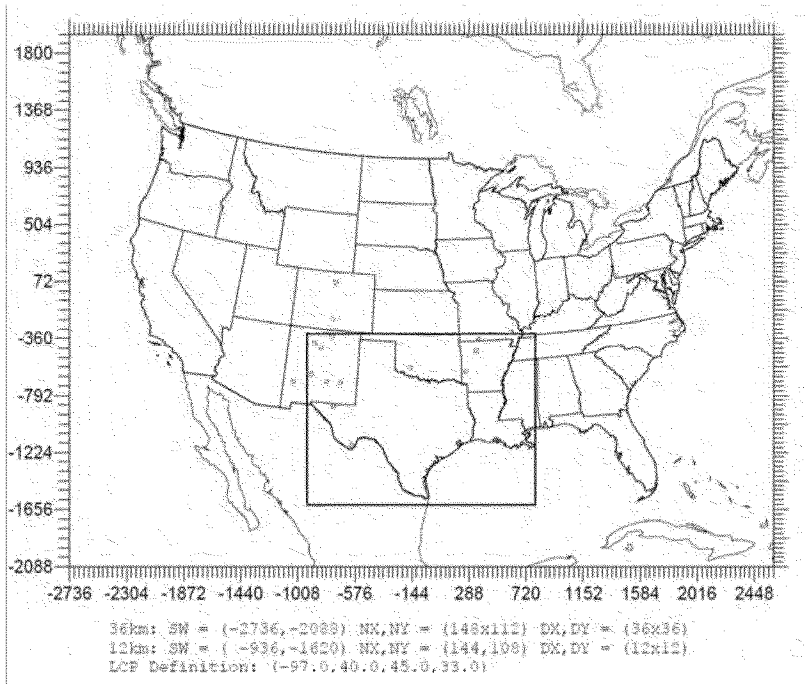
[2] Snyder, Erik, Michael Feldman, and Joe Kordzi. "Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans." U.S. EPA. November 2014.

[3] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

Figure 2-1. EPA and ENVIRON Photochemical Modeling Platform Domain[4]



2.1.2. Emissions Inventory

The CAMx model requires emissions in an hourly, speciated format. The Sparse Matrix Operator Kernel Emissions (SMOKE) pre-processor is used to process emissions data of various types of regional haze precursor emissions into a temporally and spatially allocated format. The SMOKE emissions pre-processor was configured to match the EPA's specifications and then used to process the emissions inventories used in this assessment. Version 3.1 of SMOKE was utilized in this analysis to be consistent with the EPA. The 2018 baseline scenario emissions data was used as the basis for this analysis. Each of the modeling scenarios required specific updates to the Arkansas FIP selected sources; therefore, these emissions points were updated in inventories separately from the other point source inventories and were merged into a single CAMx inventory file once SMOKE processing was complete.

2.1.3. Other CAMx Input Data

The remaining input data required to run CAMx, including but not limited to meteorological data, land-use files, albedo-haze-ozone inputs, photolysis rates, boundary and initial conditions, were unchanged from the original 2018 baseline scenario files.[5]

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[4] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

[5] Nopmongcol, Uarporn and Greg Yarwood. Memo to Ellen Belk, EPA Region 6. "2002 Baseline CAMx Simulation, Texas Regional Haze Evaluation." February 21, 2013.

2.2. ENTERGY SCENARIO ONE - BASELINE SCENARIO

The purpose of the baseline scenario is to develop a baseline level of total modeled light extinction at Caney Creek and Upper Buffalo. Additionally, the CAMx Particulate Source Apportionment Tool (PSAT) was used to trace the specific impacts of the Independence and White Bluff units as well as the remaining Arkansas sources subject to BART. In this way, the uncontrolled contribution of each source could be determined. As additional modeling is performed, the contributions of equipment from each scenario can be compared against the baseline contributions to determine the relative improvement or deterioration in visibility that can be expected due to application of various control options.

2.2.1. Emissions Inventory Updates

This regional haze assessment was based on the 2018 baseline scenario performed by ENVIRON. ENVIRON obtained the 2018 emissions inventory developed by CENRAP and incorporated selected updates, including but not limited to the addition of several new units and one new facility, the removal of several shutdown units, and the update of emission rates due to recently installed controls on selected units. Additionally, ENVIRON incorporated updates specific to the Oklahoma and Texas FIP determinations.[6]

It was noted during Entergy's initial review of these emissions inventories that two of the Arkansas sources subject to BART were not present. These two sources were the Entergy Lake Catherine Unit 4 (Lake Catherine unit) and the Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Generating Station Unit 1 (Bailey Station unit). It is believed that the growth and control factors originally used by CENRAP to project the 2018 emissions inventory may be responsible for the proposed removal of the Bailey Station unit while the Lake Catherine unit appears to have been excluded from the original CENRAP modeling. Therefore, these two units were added into the emissions inventory for Entergy's baseline scenario.

Further review of the CENRAP inventories also indicated that the stack parameters for some of the Arkansas sources subject to BART were no longer representative of actual operations. The geographic coordinates of several sources, including the Independence and White Bluff units, were likewise found to point to inaccurate locations. The stack parameters and source locations of the Arkansas sources subject to BART were therefore updated to more accurately represent the current stack characteristics.

Additionally, since the growth and control factors estimated controlled emission rate values for the Arkansas FIP selected sources, it was necessary to revise the emission rates of these sources with uncontrolled values. The Arkansas sources subject to BART, excluding the White Bluff units, were given emission rates equal to the pre-controlled values based on the 2002 NEI data. The five selected Entergy units (from the Independence Plant, the White Bluff Plant, and the Lake Catherine Plant) were updated with revised emission rates provided by Entergy representing the uncontrolled actual emissions.

A table summarizing the emission rates of the Entergy units modeled in each scenario is included in Appendix A.

2.3. ENTERGY SCENARIO TWO - ENTERGY'S PROPOSED CONTROL APPROACH

With this modeling scenario, Entergy intends to determine the expected visibility benefits of the proposed alternative to the Arkansas FIP's determinations. As discussed in earlier sections, the proposed alternative scenario includes the installation of interim controls (e.g., LNB/SOFA) on the Independence and White Bluff

[6] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

units, the reduction of SO_2 emissions, and the ultimate cessation of coal combustion at the White Bluff facility. For the purposes of this assessment, control efficiencies were applied to the NO_X and SO_2 emissions rates for the Independence units while all White Bluff emissions sources were removed from the emissions inventories to signify the cessation of coal combustion.

2.3.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) served as the basis for Entergy's Proposed Scenario. Specific emissions inventory updates include the removal of all White Bluff Plant point sources from the emissions inventories and the revision of the emission rates of Entergy's Independence units and the Arkansas sources subject to BART. The Arkansas BART sources were modeled with the proposed post-control emission rates identified in the Arkansas FIP while the Independence units were modeled with the limited control efficiencies proposed by Entergy.

2.4. ENTERGY SCENARIO THREE – PROPOSED ARKANSAS FIP SCENARIO

The purpose of the Proposed Arkansas FIP Scenario is to determine the projected regional haze impacts of applying the controls proposed to be required by the Arkansas FIP. Therefore, all Arkansas sources determined to be subject to BART and the Independence units were modeled with the control rates proposed in the Arkansas FIP.

2.4.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) also served as the basis for the Proposed Arkansas FIP Scenario. Specific inventory updates include the revision of the emission rates of all Arkansas BART sources and the Independence units to the proposed post-control emission rates identified in the Arkansas FIP.

3. ANALYSIS OF RESULTS

CAMx model outputs were post-processed and analyzed to determine the visibility effects of each of the Arkansas FIP sources. In order to obtain comparable results to EPA's CAMx modeling, the same post-processing approach was utilized, which involves the conversion of binary CAMx output files into a readable format, the extraction of relevant regional haze pollutant concentration information, and the calculation of relative response factors (RRF) using EPA's Modeled Attainment Test Software (MATS). Calculation workbooks also provided by the EPA were then used to determine visibility impacts. The full post-processing procedure used to analyze each modeling scenario is discussed in detail below.

3.1.1. Introduction to Atmospheric Visibility

The primary purpose of the Regional Haze Rule is to improve visibility at mandatory Class I areas. In practical terms, visibility at Class I areas is most simply measured as the farthest distance that can naturally be seen by an average human. Light waves diffract and are absorbed as they pass through and around particles and molecules in the atmosphere. The level of visibility therefore naturally decreases at greater distances as light waves come into contact with a greater number of these miniscule obstacles. This scattering of light waves is called Rayleigh scattering. In eastern areas of the United States, it is estimated that without the effects of anthropogenic pollution, visibility is naturally limited to a distance of approximately 90 miles, while in western areas the natural visible range is approximately 140 miles.[7]

As atmospheric concentrations of particles and molecules increase, the level of visibility further decreases since light waves can potentially interact with a larger number of obstacles at equivalent distances. Therefore, pollution from both anthropogenic and non-anthropogenic sources can have a significant effect on visibility in Class I areas. The primary contributors to visibility impairment include sulfates, nitrates, organic carbon, elemental carbon, crustal material, and sea salt."[8, 9]

In addition to visual range, another useful visibility measurement is the light extinction coefficient, which represents the gradual decrease in light intensity due to absorption and scattering. The light extinction coefficient can be calculated using measured concentrations of the primary contributing species to visibility impairment.[10] At Class I areas, the concentrations of these species are monitored by the Interagency Monitoring of Protected Visual Environments (IMPROVE), which analyzes 24-hour duration samples every 3 days. In 1999, an equation to estimate light extinction based on available IMPROVE data was incorporated into the Regional Haze Rule (Old IMPROVE equation). In 2007, a revised equation was developed to reduce "bias for high and low light extinction extremes" and to make the equation "more consistent with the recent atmospheric aerosol literature." This equation is given as follows:

---

[7] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress.* EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

[8] Ibid.

[9] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[10] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress.* EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

2.2
- 4.8
- 2.4
- 5.1
- 2.8
- 6.1
- 10
- 1
- 1.7
- 0.6
-
- 0.33

Where b_{ext} represents the light extinction coefficient in inverse megameters (Mm^{-1}), and individual species concentrations are shown in brackets with units of micrograms per cubic meter ($\mu g/m^3$). The f_L and f_S terms are unitless water growth factors given as functions of relative humidity (RH) for concentrations of large and small sulfates and nitrates, while f_{SS} represents the water growth factor for sea salt concentrations. The numerical constants given in the equation (e.g., 2.2) represent dry mass extinction efficiency terms in units of square meters per gram (m^2/g).[11]

Because the units for the light extinction coefficient (MM^{-1}) are difficult to conceptualize and compare in practical terms, the deciview haze index (dv) was developed. The deciview haze index is calculated as a function of the ratio of the calculated light extinction coefficient to the approximate average extinction value due to Rayleigh scattering alone (10 Mm^{-1}).

$$10 \ln \left(\frac{\quad}{10} \right)$$

The deciview scale provides a simpler representation of visibility deterioration, with natural conditions having a calculated deciview haze index of approximately zero, depending on the site-specific level of Rayleigh scattering.[12]

3.1.2. MATS Processing

The raw CAMx output data most relevant to this regional haze assessment includes an overall average concentration file and a source apportionment concentration file, for each grid utilized (i.e., 12 km and 36 km grids) and for all modeled dates. These raw output files are in Fortran binary and are based on the Urban Airshed Model (UAM) convention. Several post-processor utility programs are used to convert these UAM formatted output files into MATS ready comma separated value (CSV) input files for individual source groups identified by PSAT.

MATS forecasts the level of visibility at Class I areas by using post-processed CAMx modeling output in accordance with monitoring data from the IMPROVE program. The three primary files required to run MATS are

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[11] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[12] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress.* EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

the base year model CAMx output, the future year model CAMx output, and the IMPROVE monitoring data. For the purposes of this modeling assessment, 2002 was selected as the base year. The 2018 future year model output refers to each of the CSV files created. The IMPROVE monitoring data is provided as sample data in the MATS software package download from the EPA.

First, MATS uses the IMPROVE monitoring data to identify the 20% best and 20% worst visibility days at each Class I area for the base year, 2002. Using the base year modeled output data on these exact same 20% best and 20% worst days, MATS calculates the average 20% best and 20% worst modeled concentrations of each of the pollutants identified (e.g., sulfates, nitrates, etc.). MATS then performs the same calculations using the same days with the 2018 future year model data. These values are next used to calculate relative response factor (RRF) values, which are ratios of future year modeled concentrations to base year modeled concentrations, both predicted near the same Class I area. The result of this step is a set of best and worst RRF values calculated for all identified species at each Class I area. These RRF values are used in accordance with IMPROVE monitoring data to forecast future deciview haze index values.

The final output from the MATS analysis includes, but is not limited to, the best and worst RRF values calculated for each species and Class I area, the best and worst average daily deciview haze index values for each valid year and Class I area, and the annual average deciview haze index values for each Class I area. In order to perform the required calculations for the PSAT source contribution analysis, all eleven PSAT-negated CSV files were also processed by MATS so that specific PSAT-negated RRF values could be calculated for each PSAT source. These RRF values represent the relative response of each modeled pollutant concentration resulting from the removal of each PSAT source.

3.1.3. PSAT Source Contribution Analysis

The PSAT source contribution analysis determines the individual impact of each PSAT source on visibility at Class I areas. As described in earlier sections, the impacts of the Arkansas BART sources and Entergy's Independence units were traced by the CAMx PSAT tool. The source apportionment CAMx output files were post-processed through MATS to calculate RRF values, which were then used in contribution analysis workbooks provided by the EPA. The calculations in these workbooks are based on the New IMPROVE equation, the IMPROVE monitor data, and the RRF values calculated by MATS.

The contribution analysis workbooks are designed to retrieve the monitored concentrations of visibility impairing pollutants associated with the 20% worst visibility days from 2002 (base year) IMPROVE data, and to multiply them by the 2018 future year RRF values as well as the PSAT-negated RRF values associated with each PSAT source. The resulting values are input to the New IMPROVE equation, which calculates the 2018 projected light extinction values for each of the 20% worst days. These extinction values are averaged and converted into deciview haze index values. PSAT-negated haze index values represent the total 2018 deciview haze index value minus the contribution of the individual PSAT source.

The individual impact of each PSAT source is calculated as the difference between the total 2018 future year haze index value and each PSAT-negated haze index value. For this assessment, the contributions of individual sources located at the same facility were combined in order to compare facility contributions. Figures 3-1 and 3-2 display the uncontrolled baseline scenario facility contributions to deciview haze index for Caney Creek and Upper Buffalo, respectively.

Figure 3-1. Contribution Analysis Results for the Baseline Modeling Scenario at the Caney Creek Wilderness Area

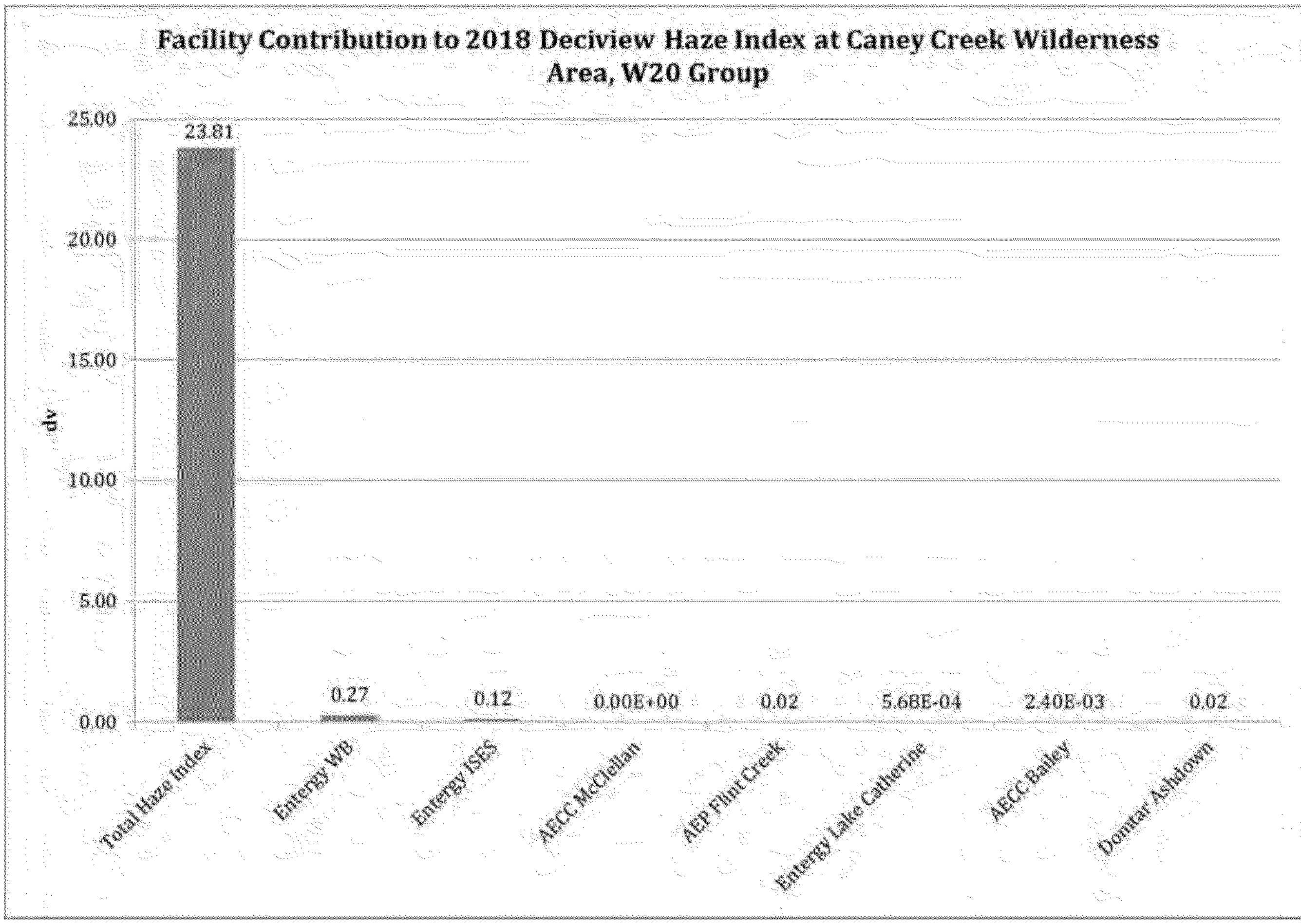
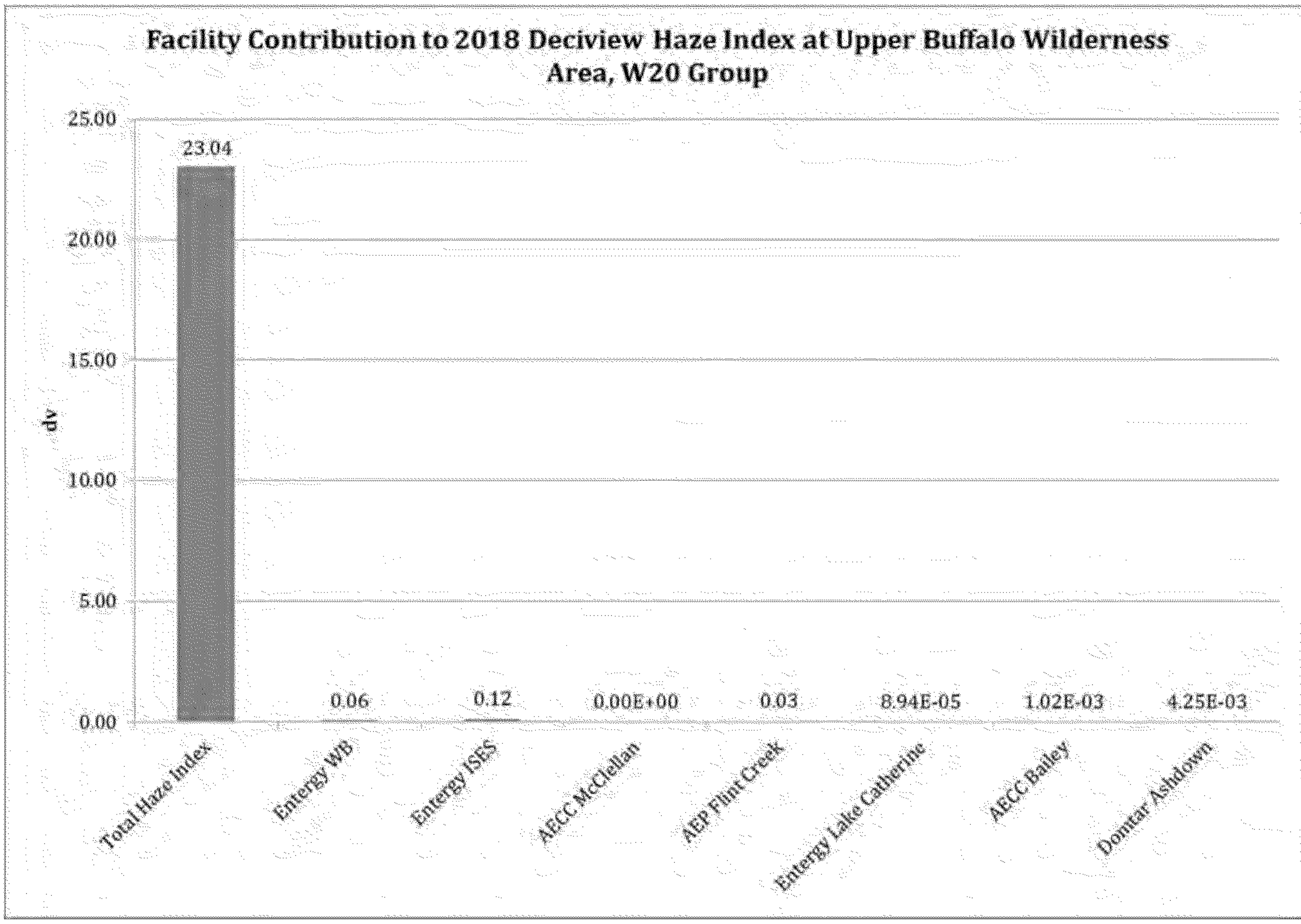


Figure 3-2. Contribution Analysis Results for the Baseline Modeling Scenario at the Upper Buffalo Wilderness Area



3.1.4. Uniform Rate of Progress Curve Analysis

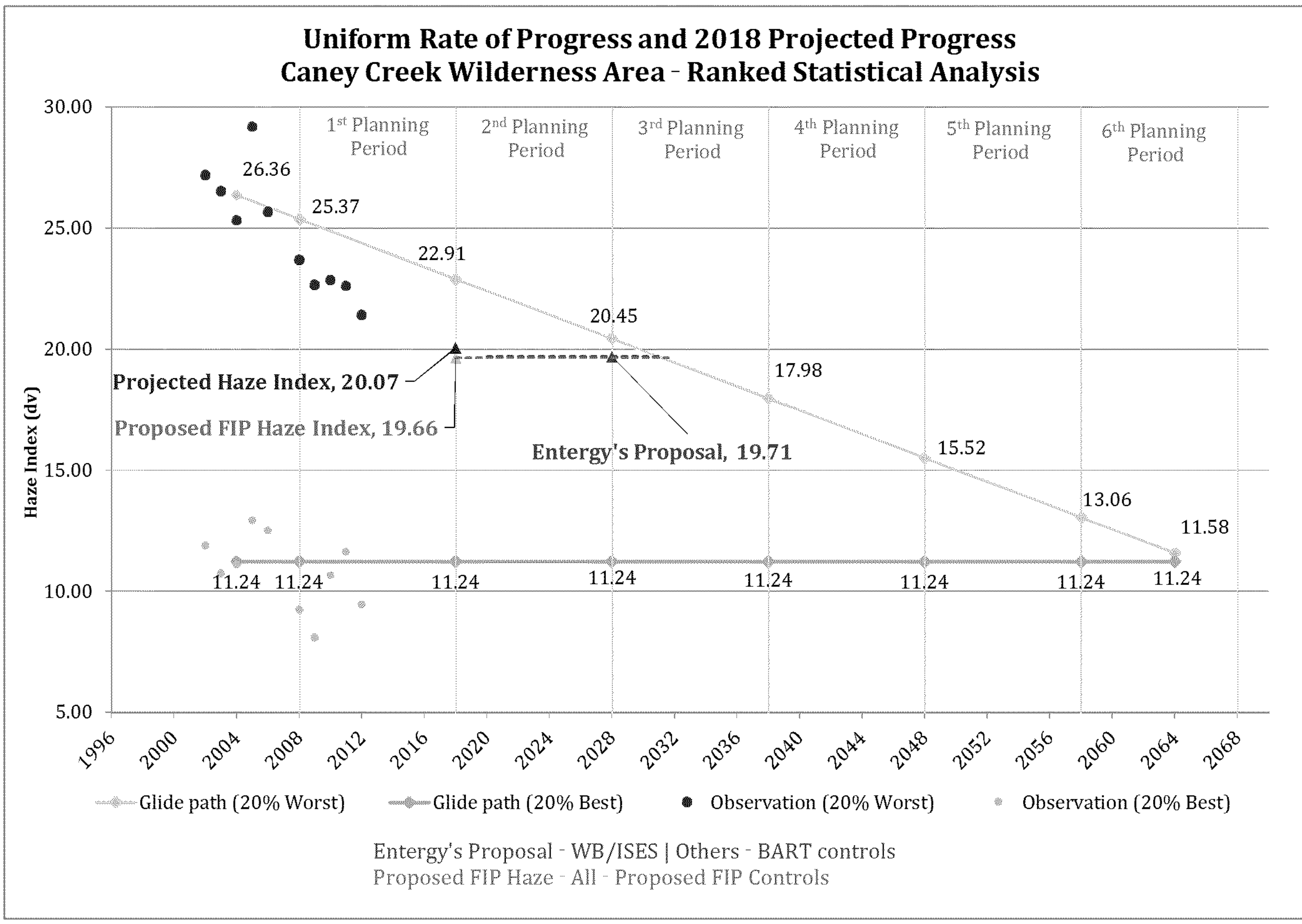
Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIPs "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[13] This requirement is demonstrated by creating a URP graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs are typically initiated in 2004 based on average 2002-2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 initial haze index values are then projected into the future at the minimum rate required to attain natural visibility conditions by 2064. Figures 3-3 and 3-4 display URP curves for Caney Creek and Upper Buffalo, respectively.

Each of these figures display the 20% best and 20% worst URP curves, the average of the 20% best and 20% worst observed deciview haze index values for each year of complete IMPROVE data, and projected haze index values for each modeled scenario. The Projected Haze Index values are obtained from a statistical analysis

[13] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

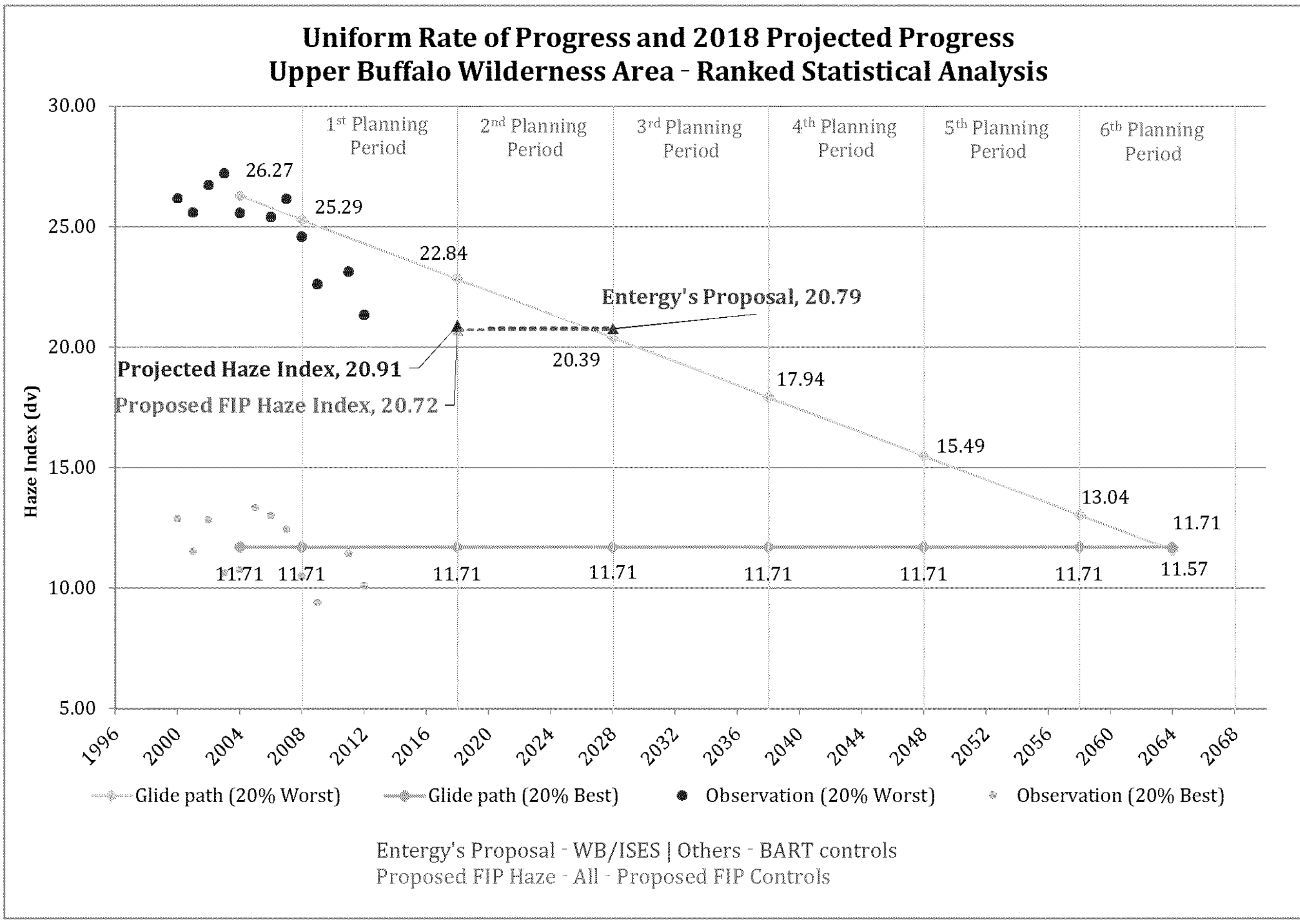
performed using the full set of IMPROVE data for both Caney Creek and Upper Buffalo.[14] The scenario-specific haze index values are calculated by first converting the model-predicted five-year averaged haze index values obtained from MATS into total extinction values in Mm^{-1}. The predicted improvement associated with each scenario is then calculated by finding the difference between the extinction values from the scenario of interest (i.e., Proposed FIP or Entergy's Proposal) and the uncontrolled baseline scenario. The improvement from each scenario is then subtracted from the Projected Haze Index value and converted back into deciviews to obtain scenario-specific haze index values.

Figure 3-3. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Caney Creek Wilderness Area



[14] Trinity Consultants. "IMPROVE Data Statistical Analysis: Discussion and Methodology for IMPROVE Data Statistical Analysis." July 2015.

Figure 3-4. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Upper Buffalo Wilderness Area



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APPENDIX A: MODELED EMISSION RATES

Appendix Table A-1. Modeled Emission Rates for the Entergy Independence and White Bluff Units

Unit	Uncontrolled Baseline (tpy)		Entergy's Proposal (tpy)		Arkansas FIP (tpy)	
	NO_X	SO_2	NO_X	SO_2	NO_X	SO_2
Independence Unit 1	6,313	14,258	3,150	12,154	3,619	1,357
Independence Unit 2	6,516	15,407	3,347	13,162	3,167	1,521
White Bluff Unit 1	7,580	15,939	--[1]	--[1]	4,145	1,453
White Bluff Unit 2	8,145	16,034	--[1]	--[1]	4,060	1,476
Lake Catherine Unit 4	1,228	3.26	564	3.26	564	3.26

[1] Entergy's Proposal includes the cessation of coal combustion at White Bluff.

IMPROVE DATA STATISTICAL ANALYSIS

Entergy Arkansas Inc.

Discussion and Methodology for IMPROVE Data Statistical Analysis

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July 2015

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the proposed Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) which the EPA disapproved in its final action, published March 12, 2012. [1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) and reasonable progress control requirements. Specifically, the EPA proposed to meet RPGs by presenting options for controlling emissions from the Entergy Arkansas Inc. (Entergy) Independence Plant (ISES), which is not subject to BART.

Trinity Consultants Inc. (Trinity) was tasked with conducting a statistical analysis of observed visibility data gathered through the Interagency Monitoring of Protected Visual Environment (IMPROVE) program to statistically determine the future trends in the regional haze index values. Trinity conducted a simple Trend Statistical Analysis and more robust Ranked Statistical Analysis to determine the projected haze index in 2018.

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. INTRODUCTION

Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIP “analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064.”[2] This requirement is demonstrated by creating a Uniform Rate of Progress (URP) graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs, also known as glide paths, are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs typically were initiated in 2004 based on average 2002 – 2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 values were then projected into the future to intersect with the 20% best days observed value by 2064. To demonstrate attainment with this glide path, the Central Regional Air Planning Association (CENRAP) used the Comprehensive Air Quality Model with Extensions (CAMx) to perform regional haze modeling. The model-predicted haze index values based on the future projected emission rates are used to compare with the glide path proposed value in 2018, the end of the 1st planning period. Figures 2-1 and 2-2 display the uniform rate of progress glide paths for the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo) along with the CENRAP projected haze index.

In addition to the glide paths for the 20% worst days and 20% best days, the URP graphs also present the observed 20% worst and 20% best haze index values from the IMPROVE monitoring observational data for 2002 to 2012. As presented in Figures 2-1 and 2-2 for Caney Creek and Upper Buffalo, respectively, the observed values are well below the glide path with a consistent downward trend in the observations. This downward trend is consistent with the historical (2002 – 2011) trend in decreasing sulfur dioxide (SO_2) emissions from tier 1 sources located in the states contributing significantly to the Caney Creek and Upper Buffalo Class I Areas. Figure 2-3 presents the National Emissions Inventory (NEI) SO_2 emissions from 2002, 2005, 2008, and 2011. Pursuant to the NEI emissions data, the SO_2 emissions have significantly decreased since 2005 to 2011 in all source categories, including especially a more than 50% drop due to fuel combustion from electric utilities and a 67% drop in the fuel combustion from industrial sources. Based on the significant downward trend in the observed data and the actual SO_2 emissions data, the future haze index value in 2018 is expected to be lower than the currently predicted glide path. The lower haze index value in 2018 will be additionally supported by the anticipated implementation of regulations further curbing emissions.

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[2] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

Figure 2-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

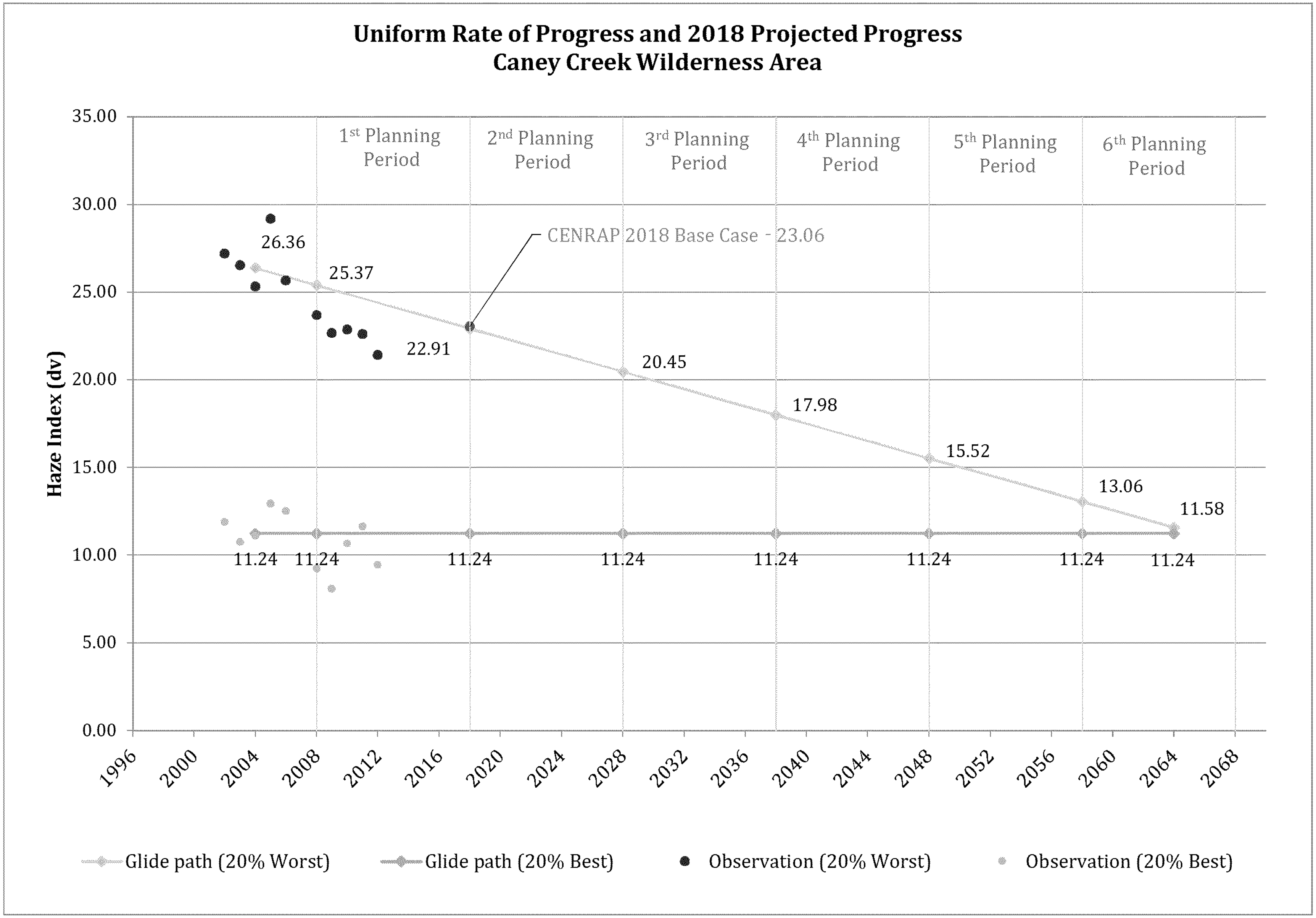


Figure 2-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

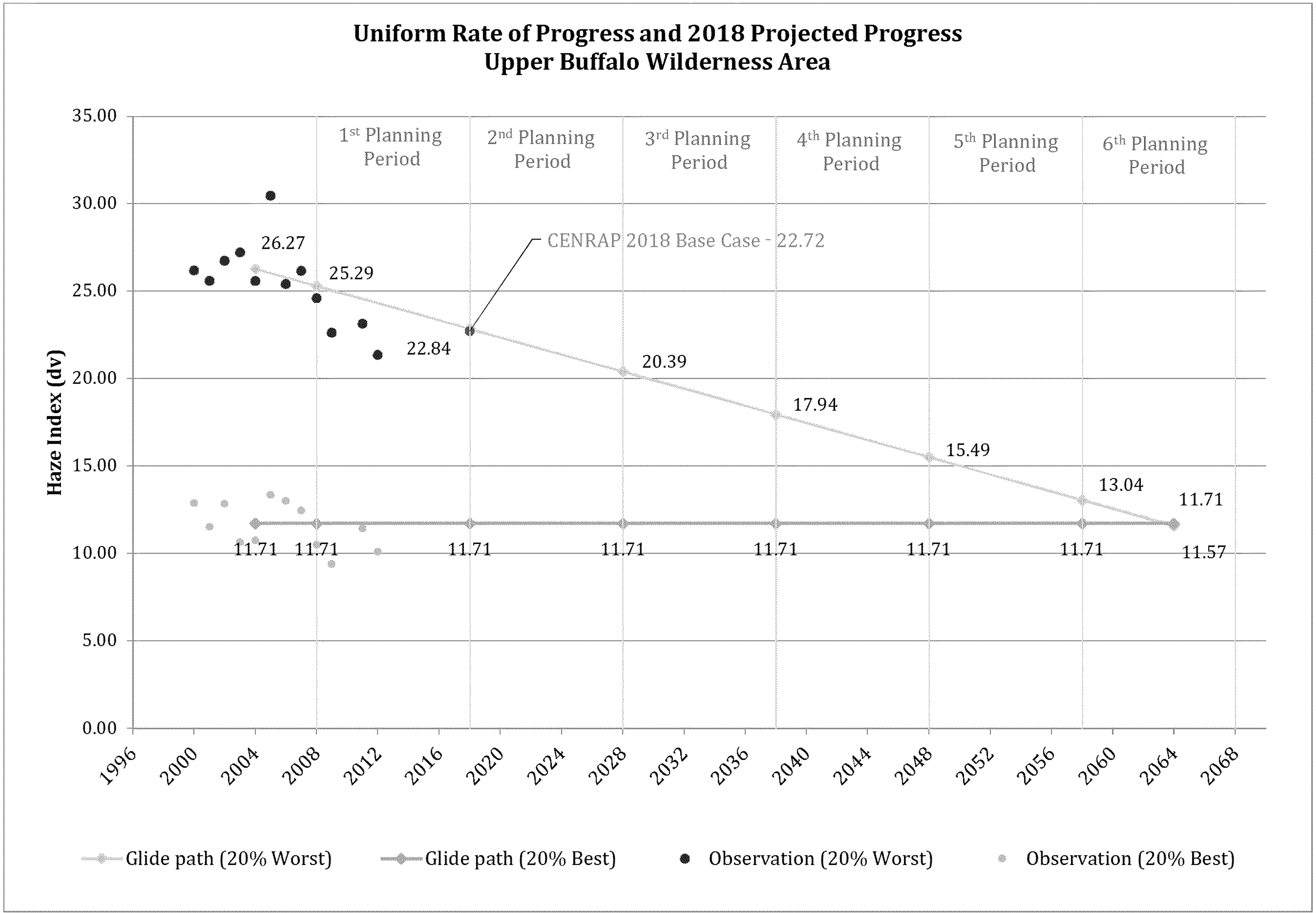
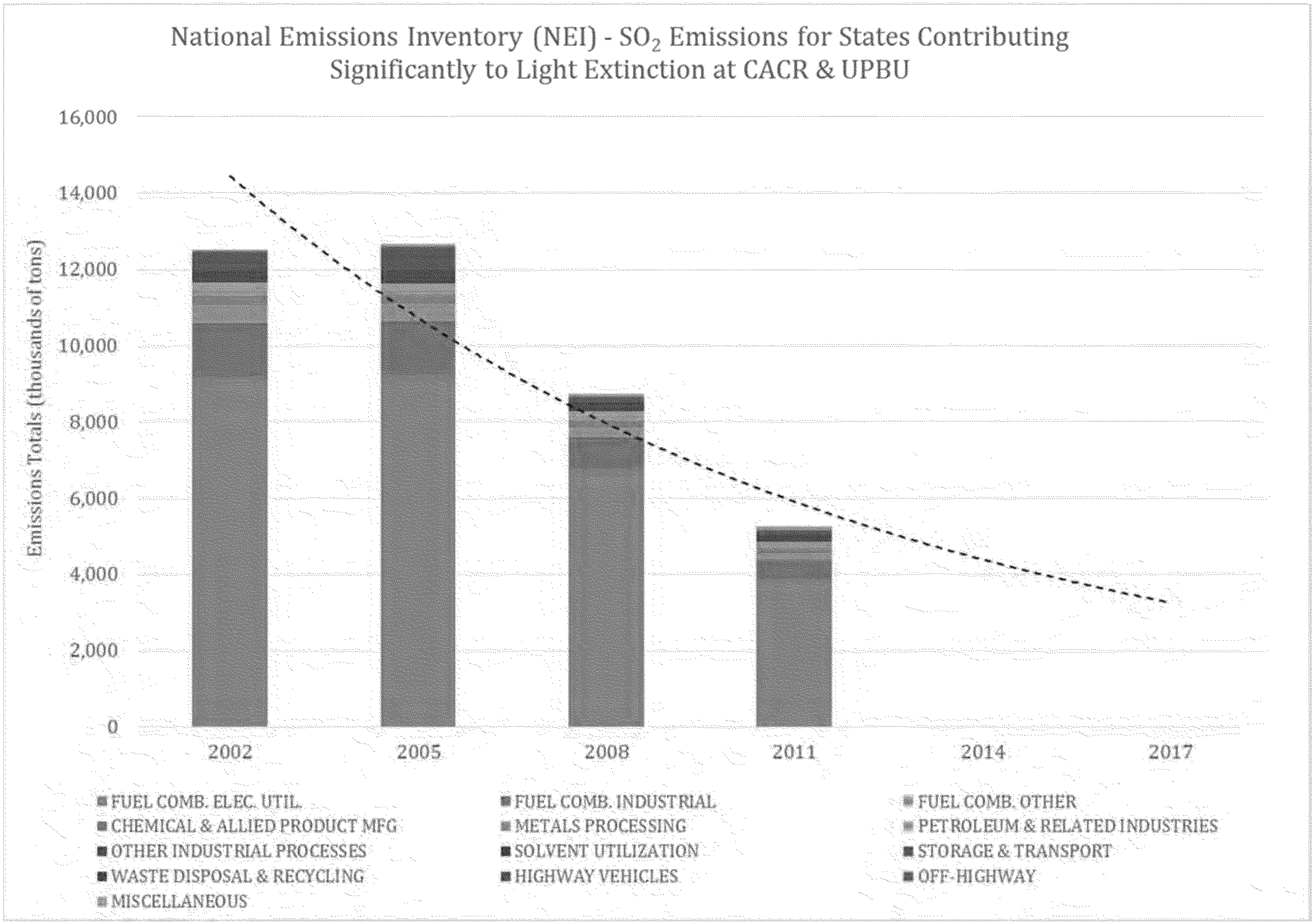


Figure 2-3. National Emissions Inventory (NEI) – SO_2 Emissions for States Contributing Significantly to Light Extinction at Caney Creek and Upper Buffalo



Based on the above, when looking at the observed values, the CENRAP model predicted regional haze value for 2018 is overly conservative and over predicting the future haze index. Although the predicted 2018 haze index values are good conservative estimates for attainment demonstrations, the values are misleading when assessing the effect of proposed controls on single sources. Additionally, the CENRAP CAMx model predicted haze index does not account for the observed values and the trend predicted if an assessment occurred evaluating the observed values. Therefore, instead of using the CENRAP CAMx predicted 2018 haze index to understand the effect of the control options, a statistically derived projected haze index must be used.

In order to statistically calculate the future deciview haze index values using observed data instead of relying on the CENRAP modeling, two statistical analyses were performed and evaluated to determine the most appropriate analysis for predicting the haze index values based on observed data:

- Trend Analysis
- Ranked Statistical Analysis

Each of these analyses are summarized in Section 3 of this report.

3. STATISTICAL ANALYSIS

3.1. TREND STATISTICAL ANALYSIS

A trend analysis using a simple least squares linear regression based on the annual average values was performed. Using this simple “Trend Analysis” methodology, the projected 2018 deciview haze index values of **18.02** dv and **20.44** dv were determined for Caney Creek and Upper Buffalo, respectively. Figures 3-1 and 3-2 present the uniform rate of progress glide paths for Caney Creek and Upper Buffalo when the 2018 projected haze index is based on the statistical trend of the observed data. These values are estimated without consideration of additional controls added as a result of the proposed FIP. Presented alongside these projected values are the estimated values that would result from adopting the proposed FIP controls (Proposed FIP Haze Index) as well as the controls proposed by Entergy (Entergy’s proposal). Entergy’s proposal includes meeting more stringent SO_2 emission rates at ISES and Entergy’s White Bluff plant (WB) by 2018, the installation of low nitrogen oxides (NO_X) burners at ISES and WB, and the cessation of coal combustion at the WB plant by 2028.

This statistical analysis is not, however, a realistic model for expected visibility improvement since this trend is based on a limited set of data—the 20% worst deciview haze index values for each year—which may not be representative of the complete set of IMPROVE data. Therefore, a more extensive statistical analysis was performed to predict future deciview haze index values based on the full set of IMPROVE observation data.

A review of the IMPROVE data sets for both Caney Creek and Upper Buffalo indicate that there is no convincing correlation between the observed deciview haze index value and the date of observation. That is, there is no detectable temporal trend in the IMRPOVE data. However, as shown in Figure 3-3, the maximum, third quartile, median, first quartile, and minimum data points do indicate a consistent downward trend from year to year, which suggests that over time, from year to year and month to month, the first highest, second highest, third highest, etc. observed values will follow a trend which can be used to predict future values.

IMPROVE data obtained for both Caney Creek and Upper Buffalo spanned the years 2000 to 2012 where data is taken every three days. However, both IMPROVE data sets contain regions of time for which data is not available. Because some years have less data points than other years, it is therefore impossible to predict future deciview haze index values using the n^{th} largest value without introducing unnecessary biased skew. For example, the Caney Creek IMPROVE data for 2000 includes only 52 values while 2004 contains 122 values. Therefore, the 52^{nd} highest value (also the minimum value) for 2000 is 4.04 dv while the 52^{nd} highest value for 2004 is 20.00 dv. Since it would be inappropriate to compare the minimum value of 2000 with a value closer to the median of 2004, further refinement to the methodology is required.

One option is to simply remove years with data not meeting a defined criteria for completeness. This option, however, is not preferred because it discounts a large quantity of valuable data. Additionally, this option only slightly reduces the potential for skew described above. The final chosen methodology (Ranked Statistical Analysis) addresses both of these issues by minimizing the skew due to incomplete data while maximizing the usage of available data.

Figure 3-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

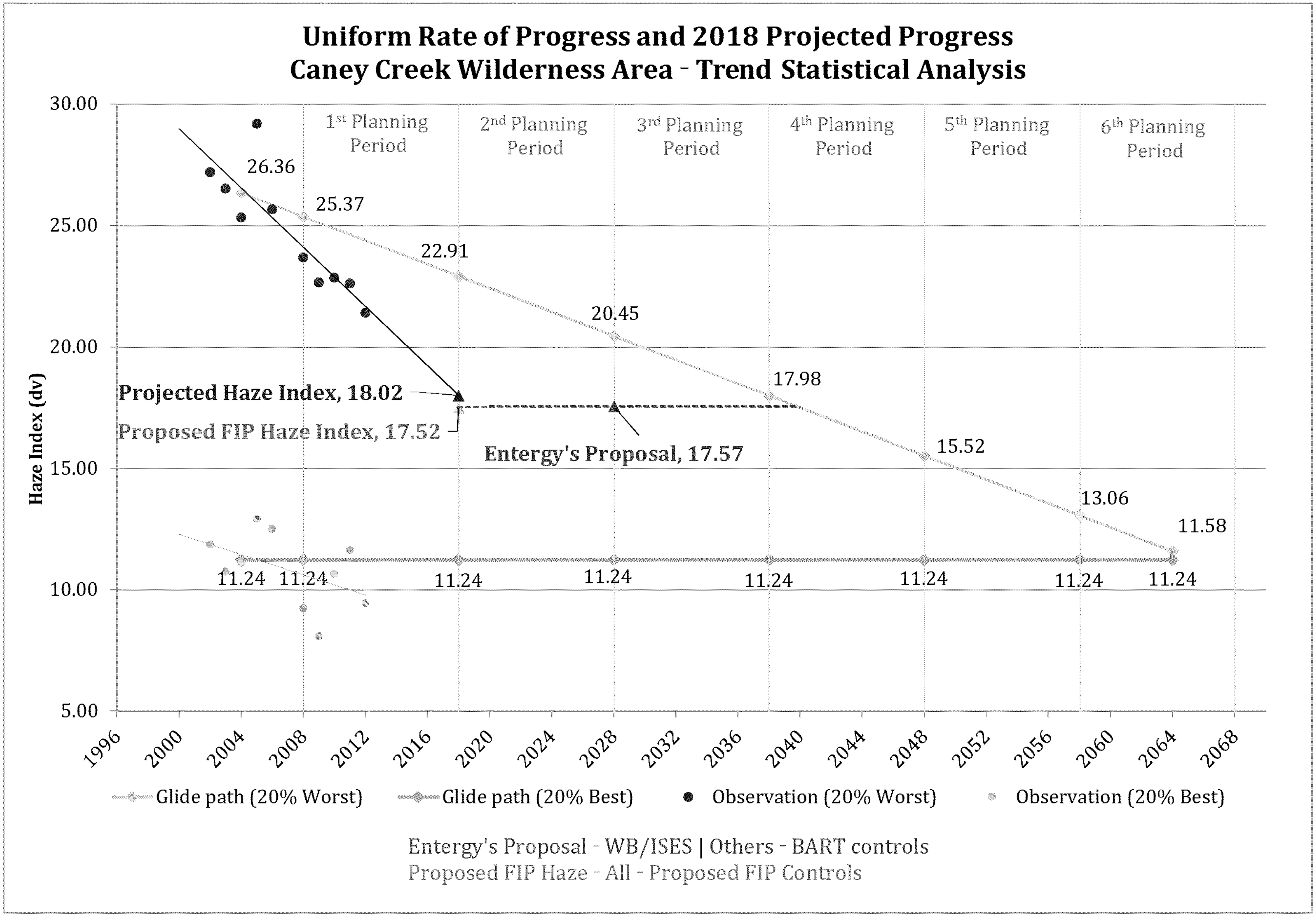


Figure 3-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

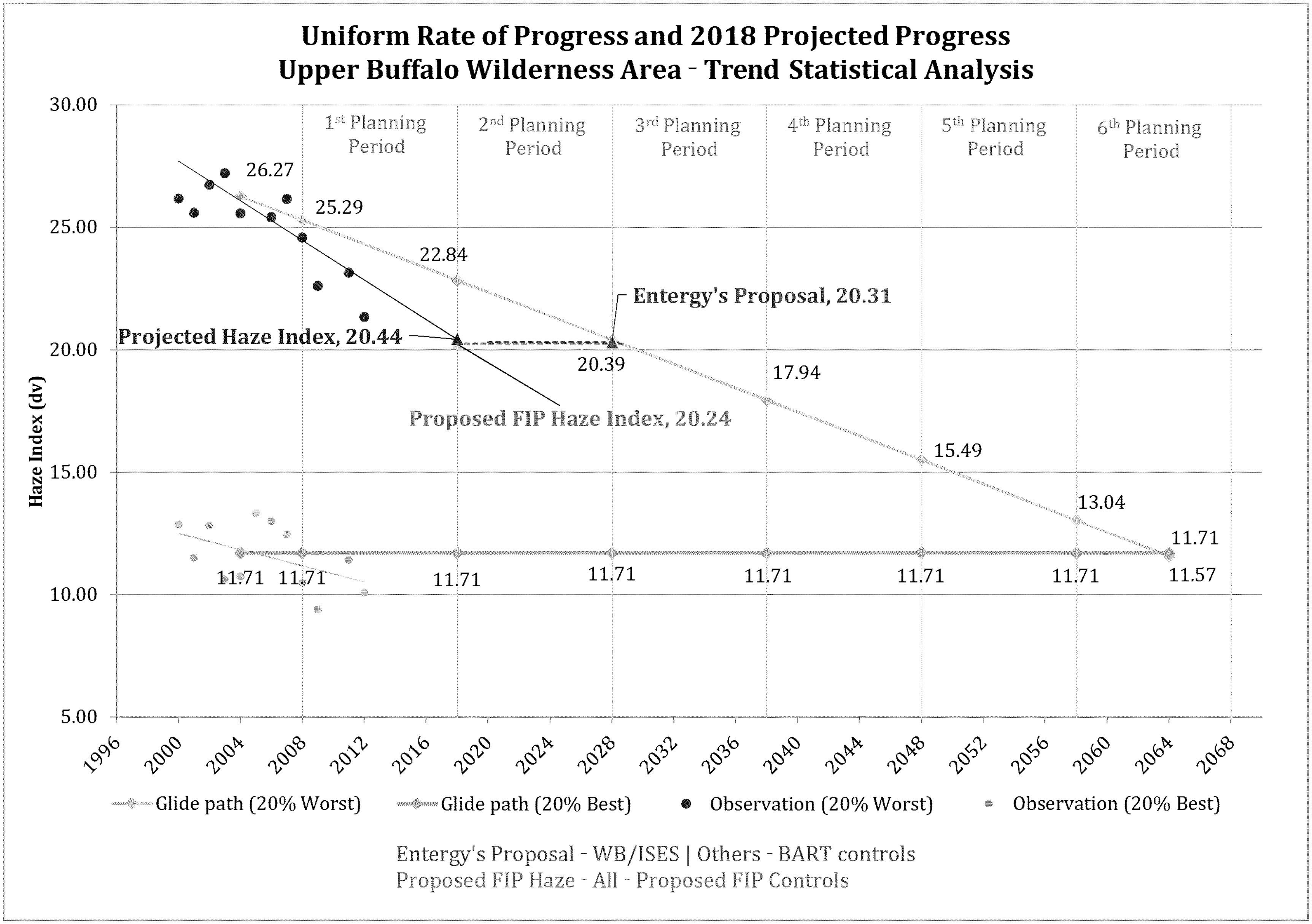


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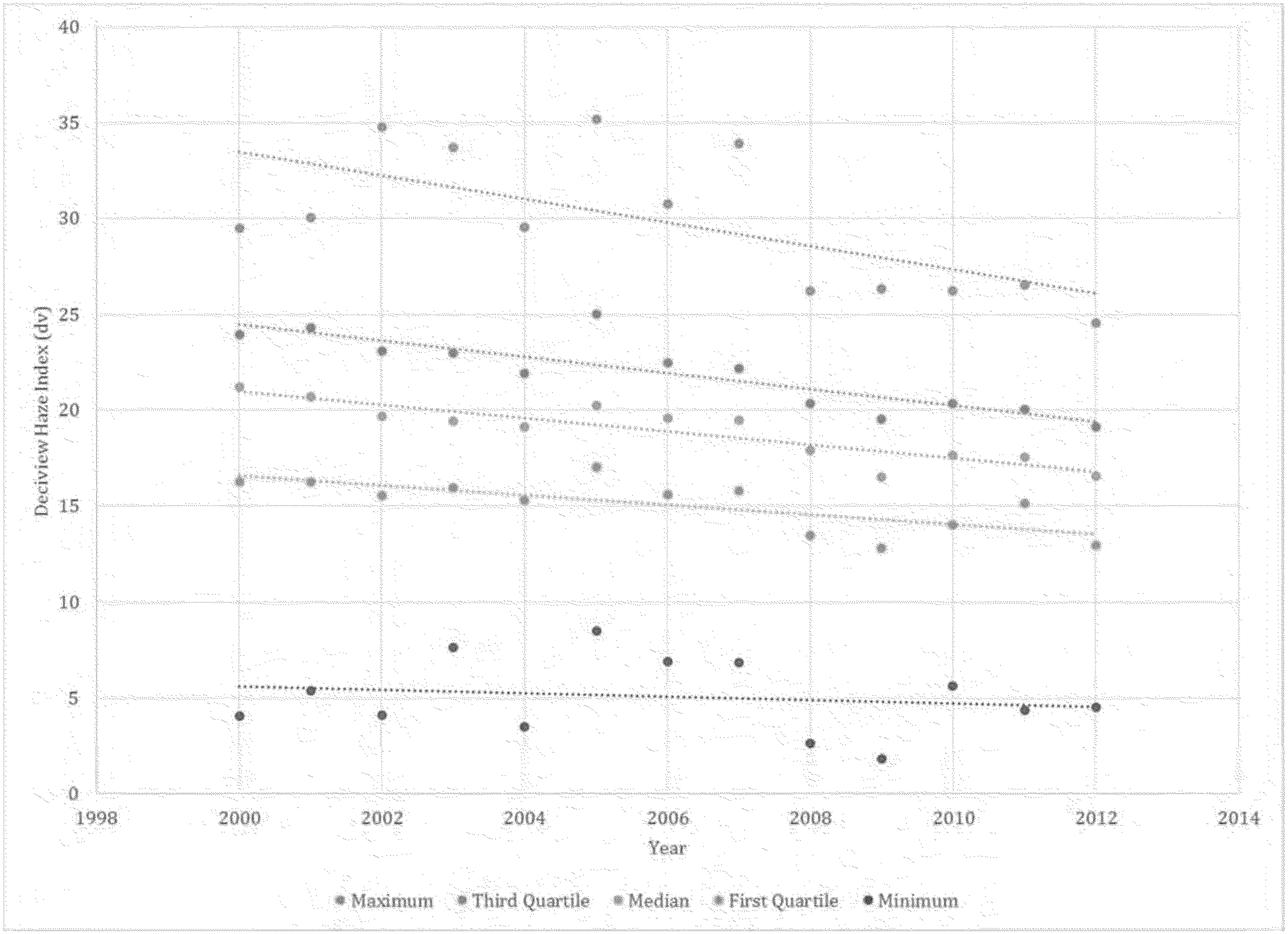
Figure 3-3. Observed Trends in Statistical Values for Caney Creek IMPROVE data.



3.2. RANKED STATISTICAL ANALYSIS

The chosen methodology, described as Ranked Statistical Analysis, begins with the chronological organization of the IMPROVE data from every year, as displayed in Table 3-1 as an example. It was determined that a month of data is incomplete for a year if less than nine (9) days of data points are available (eight days for February) for that month. This completion criteria corresponds to approximately overall 90% completeness. Table 3-2 presents the resulting completeness determinations of each month and year for Caney Creek. If a given month has less than nine out of thirteen years of complete data, that month is discounted from the calculations and is not considered in the future projections. As shown in Table 3-2, April only had eight years of complete data for Caney Creek; therefore, April was not considered in the projections. Once the completeness determination was completed, the haze index values for each complete month and year were then ranked so that the values for each month from year to year were aligned in descending order. Table 3-3 presents the ranked observations for Caney Creek for the complete years of January data as an example. These ranked monthly values were used to predict the daily haze index values for each month of the year 2018. Using this set of predicted 2018 values, the 2018 average of the 20% worst days for visibility was calculated to be **20.07** dv for Caney Creek and **20.91** dv for Upper Buffalo. Figures 3-4 and 3-5 display these predicted 2018 values in relation to the URP curves for each Class I Area. Also displayed are the estimated proposed FIP haze index and the haze index based on Entergy's proposed controls.

The haze index values predicted using the Ranked Statistical Analysis are consistent with the downward trend from the observed values and are more conservative than the Trend Analysis. The Trend Analysis relies on the sampling data generated from average worst 20% days IMPROVE data and therefore, the sampling data is limited to only one (1) value per year. This limited size of sampling can induce some bias in the statistical analysis. However, the statistical samples in the Ranked Statistical Analysis, unlike the Trend Analysis, includes at least nine (9) values per month or a minimum of 108 data points for each complete year. The sample data used for the Ranked Trend Analysis included at least 8 complete years or a minimum of 860 data points. The use of this large data sample in the Ranked Statistical Analysis makes this analysis more robust and un-biased in predicting the projected trends. The use of a larger sample point ranked on a monthly basis also preserves the temporal and diurnal patterns in the observed data. By predicting monthly future values, these diurnal and temporal pattern are sustained in the statistical analysis and therefore, reduce the bias due to missing values.

Based on statistical analysis completed, the Ranked Statistical Analysis is more appropriate for determining the downward trend in the haze index based on IMPROVE observed data. When comparing the ranked versus trend analyses, the trend analysis would suggest the programs external to the Regional Haze rule will have a more profound effect on the glide path which will approach the natural background in 2028 and 2042 for Caney Creek and Upper Buffalo, respectively. When looking at the more conservative Ranked Statistical Analysis, the URP will be approached after 2038/2044 for Caney Creek and Upper Buffalo, respectively, but well before the 2064 deadline. Under either approach, analysis of the data trends show that the rate of visibility improvement is outpacing the URP graphs at both Caney Creek and Upper Buffalo.

Table 3-1. Chronological Deciview Haze Index Values Observed in January at the Caney Creek Wilderness Area

Julian Day	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1	--	--	--	--	14.59	--	--	--	10.24	18.60	--	--	11.70
2	--	--	21.27	--	--	--	--	--	--	--	20.47	--	--
3	--	--	--	19.27	--	--	--	18.54	--	--	--	14.72	--
4	--	--	--	--	13.18	11.69	--	--	--	22.85	--	--	14.80
5	--	--	17.81	--	--	--	6.88	--	--	--	17.32	--	--
6	--	--	--	20.09	--	--	--	23.10	--	--	--	12.71	--
7	--	--	--	--	15.61	10.71	--	--	--	10.80	--	--	18.88
8	--	--	18.18	--	--	--	13.96	--	--	--	14.95	--	--
9	--	--	--	20.33	--	--	--	6.86	--	--	--	12.89	--
10	--	--	--	--	29.56	14.03	--	--	--	26.11	--	--	12.66
11	--	--	14.41	--	--	--	13.61	--	--	--	18.43	--	--
12	--	--	--	15.61	--	--	--	13.10	--	--	--	20.13	--
13	--	--	--	--	26.26	17.13	--	--	--	15.40	--	--	6.80
14	--	--	10.42	--	--	--	7.68	--	--	--	19.31	--	--
15	--	--	--	27.57	--	--	--	--	--	--	--	25.25	--
16	--	--	--	--	19.61	24.99	--	--	--	14.47	--	--	14.97
17	--	--	21.57	--	--	--	17.86	--	--	--	18.75	--	--
18	--	--	--	15.35	--	--	--	--	--	--	--	19.63	--
19	--	22.79	--	--	19.40	--	--	--	--	19.58	--	--	--
20	--	--	--	--	--	--	18.74	--	--	--	18.14	--	--
21	--	--	--	21.74	--	--	--	--	--	--	--	12.33	--
22	--	21.70	--	--	24.23	20.17	--	--	--	21.15	--	--	18.07
23	--	--	15.85	--	--	--	13.47	--	--	--	13.43	--	--
24	--	--	--	17.45	--	--	--	16.37	--	--	--	21.59	--
25	--	--	--	--	11.67	21.57	--	--	15.07	21.52	--	--	4.52
26	--	--	14.01	--	--	--	9.72	--	--	--	7.38	--	--
27	--	--	--	25.98	--	--	--	19.94	--	--	--	17.15	--
28	--	22.76	--	--	14.65	19.52	--	--	18.43	20.24	--	--	10.71
29	--	--	20.39	--	--	--	12.82	--	--	--	11.21	--	--
30	--	--	--	17.81	--	--	--	15.78	--	--	--	20.67	--
31	--	13.34	--	--	19.07	17.61	--	--	10.74	8.28	--	--	19.91

Table 3-2. Determination of Monthly and Yearly Data Completeness for the Caney Creek Wilderness Area

Month	Total Number Days	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Number of Complete Years
January	31	No	No	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	9
February	28	No	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	9
March	31	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	11
April	30	No	No	Yes	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes	8
May	31	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	12
June	30	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	11
July	31	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	10
August	32	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	9
September	30	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	11
October	30	Yes	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	Yes	10
November	30	Yes	No	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	Yes	Yes	9
December	31	No	No	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	9

Table 3-3. Ranked Deciview Haze Index Values for the Caney Creek Wilderness Area in January

	2002	2003	2004	2005	2006	2009	2010	2011	2012	Number of Days with Data
1	21.57	27.57	29.56	24.99	18.74	26.11	20.47	25.25	18.88	9
2	21.27	25.98	26.26	21.57	17.86	22.85	19.31	21.59	18.07	9
3	20.39	21.74	24.23	20.17	13.96	21.52	18.75	20.13	14.97	9
4	18.18	20.33	19.61	19.52	13.61	21.15	18.43	19.63	14.80	9
5	17.81	20.09	19.40	17.61	13.47	19.58	18.14	17.15	12.66	9
6	15.85	19.27	15.61	17.13	12.82	18.60	17.32	14.72	11.70	9
7	14.41	17.45	14.59	14.03	9.72	15.40	14.95	12.89	10.71	9
8	14.01	15.61	13.18	11.69	7.68	14.47	13.43	12.71	6.80	9
9	10.42	15.35	11.67	10.71	6.88	10.80	7.38	12.33	4.52	9
10	--	--	--	--	--	--	--	--	--	0
11	--	--	--	--	--	--	--	--	--	0

Figure 3-4. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis

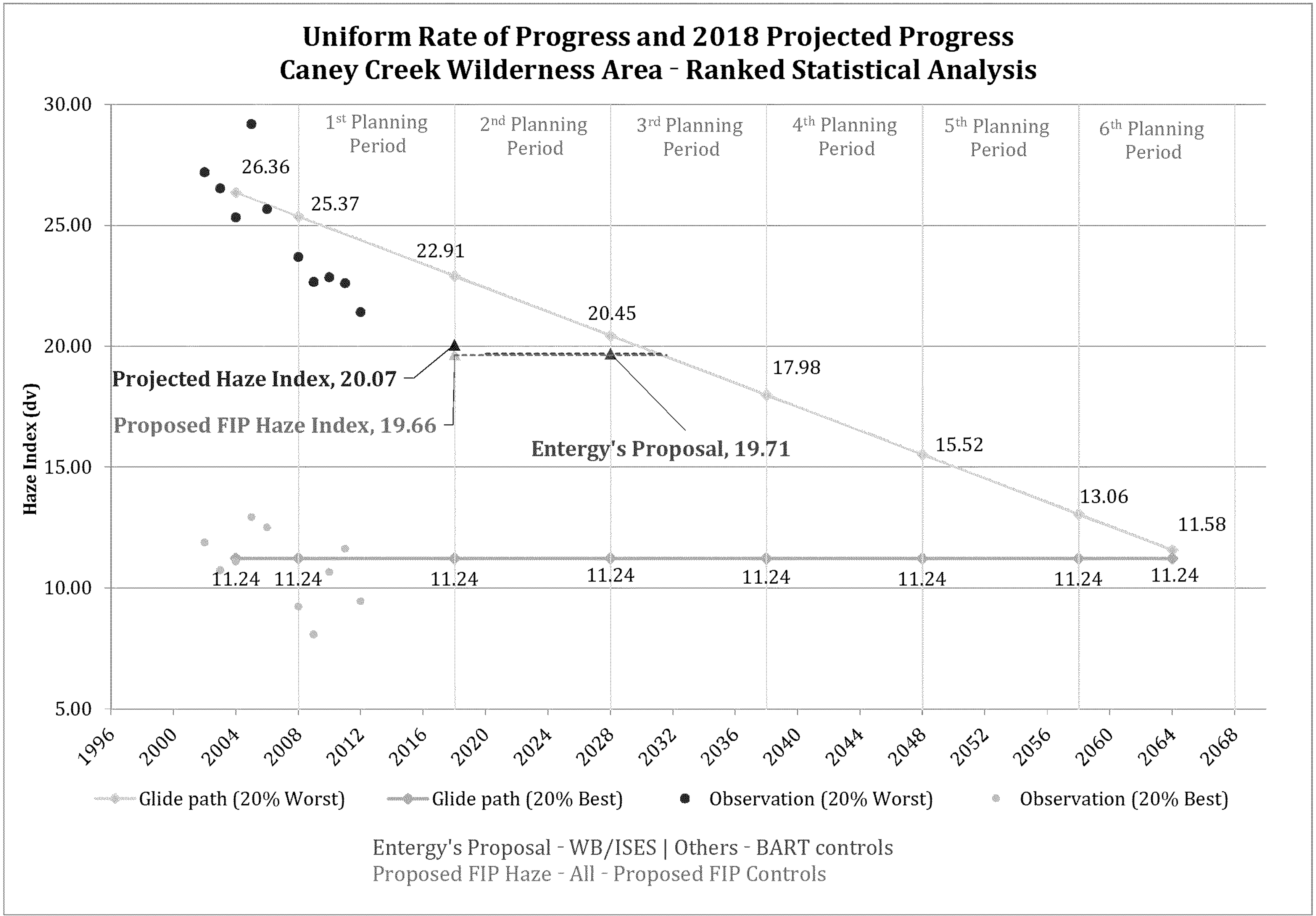
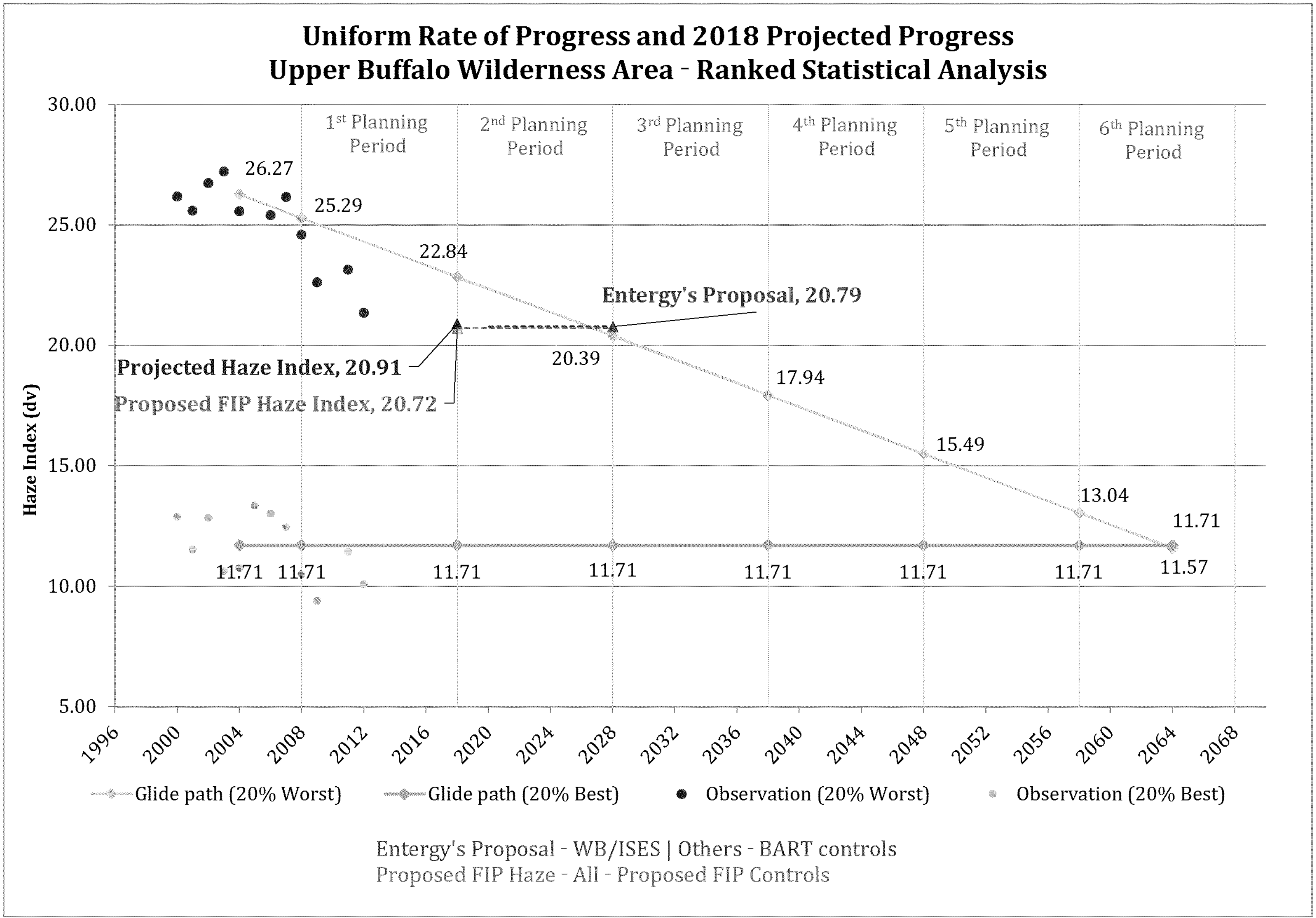


Figure 3-5. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis



TECHNICAL PAPER

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Just-Noticeable Differences in Atmospheric Haze

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ABSTRACT

This article examines the only available experimental data taken in the natural environment on the ability of an observer to perceive small, incremental changes in the colorfulness of objects seen through atmospheric haze and estimates an appropriate just-noticeable difference (JND) from these data. This experimentally determined threshold of perception is compared to changes in the deciview scale. Based on these experimental results, the deciview scale is found to not be uniform over a wide range of visibility conditions, as has been previously claimed. In addition, a 1-deciview change never produces a perceptible change in haze, as defined by a 95% probability of producing a measurable change in the colorfulness of an object seen through the haze.

INTRODUCTION

Section 169A of the Clean Air Act sets a national goal of protecting visibility in national parks and other pristine areas. Under regulations promulgated in 1980, the U.S. Environmental Protection Agency (EPA) has taken specific regulatory action to protect visibility in the Grand Canyon National Park by reducing emissions of sulfur dioxide from the Navajo Electric Generating Station near the eastern end of the Grand Canyon and from the Mohave Power Plant at the western end. However, current concerns about visibility degradation stem from regional haze that is difficult or impossible to attribute to individual sources of air pollution. This issue is addressed by regional haze regulations that set a goal of making reasonable progress toward improving regional visibility in five-year increments, leading to the attainment of "natural conditions" by 2064.[1] Progress is to be measured by an innovative visibility metric for regulatory purposes known as the deciview,[2] used instead of visual range or other visibility metrics because it "expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions."[1] One goal of this article is to assess this and other claims about the deciview scale in light of actual measurements of the perception of haziness. Since the deciview scale is meant to quantify small, just-noticeable differences (JNDs) in visibility, a review of the basic concepts of thresholds and JNDs is given.

IMPLICATIONS

Current regulations use the deciview to quantify a perceptible change in regional haze. Based on the results of this article, changes in atmospheric extinction required to meet regional haze regulations calculated using deciviews would probably be too small, sometimes much too small. In addition, these regulations require that progress be assessed over five-year intervals. In this way, the burden of reducing emissions is spread evenly over many years. However, since deciviews are not uniform in perception, it may be that the actual improvement in visibility will not be uniform.

Perceptual Threshold Concepts

For all the senses, thresholds are necessary—otherwise we would be constantly distracted by small, inconsequential changes in the environment. A background of random noise, some from the environment and some produced inside our own sensory organs, would make it next to impossible to form a stable view of the world. Our vision would be like the grainy, speckled images produced by night vision cameras. On a more basic scientific level, the study of thresholds of the senses has led to a deeper understanding of sensory physiology and how our vision and other senses function. For this reason, virtually all studies of thresholds of vision have been carried out under controlled laboratory conditions.

Since laboratory conditions seldom mimic the natural environment, thresholds so determined are generally not useful in predicting perception in the complex natural world. As an example of the drastic effect that experimental conditions can have on perception, consider an experiment to determine the ability of an observer to perceive the difference in the length of two strings—or to put it another way, to determine the threshold for perception of the difference in the length of two strings, or the JND. If the two strings are widely separated when presented to the observer, the threshold will be much greater than if the two strings are presented side by side. The visual equivalent of this is the use of a split image to determine the ability to distinguish color. If two colors are seen as two halves of a disk, the JND is very small, but if one

Exhibit E to EAI Comments

color is presented as a full disk, followed a few seconds later by the other color, the JND will be much larger. The topic of the background on which the colors are seen is also important (e.g., if it is black or a complex scene). In general, many conditions influence thresholds; for this reason, the results of laboratory experiments should be applied with great caution to the natural environment. Thus, this article will report and analyze data taken in a unique experiment in the natural environment with a goal of determining a JND in atmospheric haze.

In the above discussion, the terms "threshold" and "JND" have been freely used, but not defined. The naïve definition of a threshold or JND is clear: It is the smallest amount, or change in, a physical stimulus that is detectable. Ideally, a 1-JND change in a stimulus such as contrast or color would always result in the observer seeing a change, and anything less would not. Of course, the senses do not work in this simple on-off manner. In actuality, as the change in the physical stimulus increases, the probability that the observer will detect the change increases as well. Thus, thresholds and JNDs have always been defined by a probability of detection. Furthermore, the sensitivity of people's senses varies from person to person and during a person's life. Even if each person had a single, idealized threshold, the response of the general population would be best described by a probability of detection.

Repeated matching by the method of adjustments is one of the oldest methods of determining a JND. Falmagne[3] described this and other methods to quantify perception. Briefly, the observer is shown a target color and a variable test color and is asked to adjust the test color until it matches the target. Taking random starting points, the matching procedure is repeated as often as is practical. Since the observer has judged the matching color to be the same as the target color, the variability in the matches is a measure of a JND around the target. The standard deviation of the matches is one measure of this variability that is often used; another is the difference between the 75th and the 25th percentile of the match distribution. The method of adjustments has been replaced in laboratory studies by methods that give less control to the observer and more to the researcher and therefore improve the reproducibility of the results (unfortunately, these methods are impractical for field studies). However, JNDs are still defined by some measure related to the probability of detection. The final determination of the value of a JND or threshold is really dependent on how the measurements are made and how the data are interpreted. For the experimental data used in this article, the method of adjustments was used and a JND related to the standard deviation of repeated matches was defined.

Atmospheric Visibility Concepts

In the classical theory of atmospheric visibility, the threshold of contrast perception, that is, the threshold for perception of a large, dark object on the horizon, is assumed to be 2%.[4] This number is somewhat arbitrary. The Federal Aviation Administration (FAA) has taken the more conservative value of 5.5% as a contrast threshold for the definition of visual range, presumably because approaching aircraft seen from a cockpit are usually neither large nor dark. The common formula for visual range, using the 2% threshold, is

$$V_R = \frac{-\ln(0.02)}{b_{ext}} = \frac{3.9}{b_{ext}} \qquad (1)$$

where b_{ext} is the extinction coefficient of the atmosphere, which is assumed to be homogeneous. The extinction coefficient in the denominator of the formula can be thought of as the fraction of light that is lost as it traverses 1 m of air. For completely clear air, b_{ext} has a value of about 10×10^{-6} m^{-1} or 10 Mm^{-1}, or a visual range of about 390 km. More typically, particles in the air usually increase the extinction coefficient to 150–300 Mm^{-1} or more. Typical visual ranges are about 10 km in the eastern United States and 50 km or more in the western United States. Closely related to b_{ext} and visual range is the more general concept of optical depth. For a target at a distance x, this is defined as xb_{ext}. It is dimensionless; if b_{ext} is held constant it represents distance, and if the distance is constant, it represents changes in b_{ext}. From eq 1, the visual range corresponds to an optical depth of 3.9, and a distance of about one quarter of the visual range is equivalent to an optical depth of 1.

Despite lacking a firm psychophysical or experimental basis, the visual range defined by the 2% threshold has stood the test of time. However, while visual range has proven to be a good surrogate for atmospheric visibility for the aviation community, it is of limited value in addressing the concerns of the air quality community. Unlike aviation, where poor visibility is of greatest interest, the air quality community is primarily concerned with relatively small changes in good visibility. Pitchford and Malm[2] have proposed the deciview as a visibility indicator more suited to air quality regulations. If the extinction coefficient is given in Mm^{-1}, then deciview is defined as

$$v = 10\ln(b_{ext}/10) \qquad (2)$$

Current regional haze visibility regulations state that:

(1) A 1-deciview change in haziness is a small, but noticeable, change in haziness under most circumstances when viewing scenes in Class I areas.

(2) Deciview units are uniform in perception over a wide range of visibility conditions; that is, a 1-deciview change is just perceptible regardless of the visibility conditions.[1]

The next section describes a color matching experiment in the Great Smoky Mountains National Park. The results of this experiment are used to estimate a just-noticeable change in haze based on color perception. The validity of the claims for deciviews will be evaluated by comparison to experimental estimates of JNDs.

EXPERIMENTAL DATA

During summer 1995, a group of researchers from universities, government agencies, and private companies conducted the SouthEast Aerosol and Visibility Study (SEAVS) in the Great Smoky Mountains National Park. The SEAVS focused largely on aerosol composition,[5,6] airborne particle size distribution,[7,8] and the role of water in the aerosol.[9-11] However, the SEAVS had a number of other aspects, including a study of the perception of color through atmospheric haze.[12] The methods and primary results of the color perception study are described below.

The perceived colors of natural targets were quantified by color matching using a specially constructed visual colorimeter.[13] An observer looked at some scene element, such as a barn or green field, with one eye. The observer looked with the other eye in the visual colorimeter at a color spot, which the observer adjusted to match the color of the target. The perceived color was recorded as the amount of red, green, and blue light in the color match. At the same time, the spectrum of the light coming from the target was measured by a telespectroradiometer. A color appearance model was applied to produce measures of the perceived color as recorded by the visual colorimeter and as calculated from the spectrum.[14]

Of most interest here are the hue and colorfulness. The hue is what most people call the color—red, green, blue, yellow, and so on. It is quantified as a mixture of pure red, green, blue, or yellow lights. The colorfulness is the degree to which the hue is expressed; it is similar to the concept of saturation. A deep red color would have a colorfulness of about 100, while a colorfulness of 10 or less is almost achromatic (i.e., white or gray).

Two observers (Mahadev and Urquito) made color matches of a set of natural targets during the SEAVS. These observers were both males in their 20s with normal color vision. Each had received extensive training in color matching using the visual colorimeter. The scattering coefficient of the atmosphere was measured by a nearby nephelometer; particle absorption was small and its contribution to the extinction coefficient ignored. The full details of the experiment are found in Mahadev.[15]

The perception study found that viewing through a semitransparent atmosphere affected the perception of hue and colorfulness in a highly nonlinear way. The eye appeared to split the light coming from the target into two parts, the haze and the target. The result was that as the haze increased, the hue of the target as seen by the observer remained constant. However, because the increasing haze scattered more light into the sight path, the hue calculated from the spectrum became bluer. To the observer, the main effect of haze was to decrease the perceived colorfulness. Furthermore, the decrease in colorfulness seemed to be exponential with optical depth (optical depth is the dimensionless product of the extinction coefficient and distance):

$$M(\tau) = M_0 \exp(-\tau) \qquad (3)$$

where $M(\tau)$ is the colorfulness of the object at optical depth τ and M_0 is the colorfulness at zero optical depth (i.e., no haze). M_0 is also known as the inherent colorfulness. The colorfulness of the horizon was assumed to be small enough to be taken as zero—the horizon was perceived to be white. This result implies that a JND in colorfulness can be taken to be a JND in haze.

JND in Colorfulness

Estimates of JNDs in colorfulness were based on sets of repeated color matches made during periods when the observing conditions (cloud cover, haze level, and lighting) were judged to be constant or nearly so. Observer Urquito made six sets of repeated matches.[15] Figure 1 is a plot of all the repeated observations of the colorfulness of the red barn roof made by this observer versus optical depth. The exponential fit given by eq 1 is fairly good ($R^2 = 0.68$). The error bars in the figure are twice the standard deviation given in Table 1. They show that one set

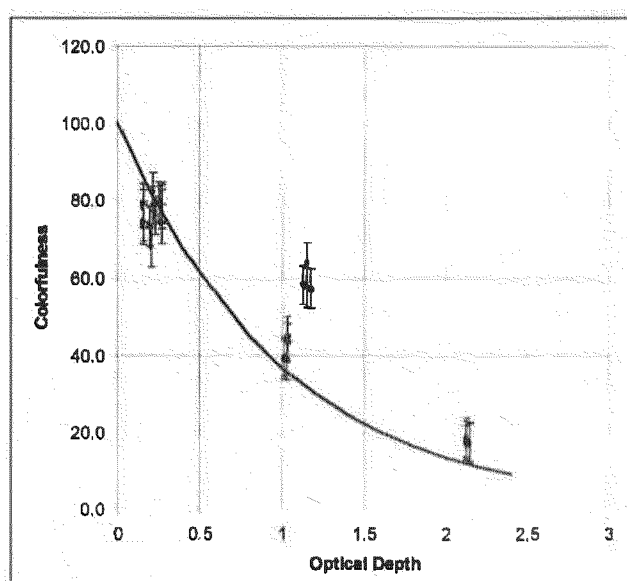

Figure 1. Colorfulness vs. optical depth for observer Urquito for repeated observations of the red barn roof. The line is an exponential fit as in eq 1, and the error bars are two times the standard deviation given in Table 2.

Table 1. Repeated measurements of the red barn roof by observer Mahadev.

Date	Time	Scattering Coefficient $(Mm)^{-1}$	Visual Range (km)	Colorfulness Spectra	Colorfulness Perceived	Spectra Hue % Red	Spectra Hue % Blue	Perceived Hue % Red	Perceived Hue % Blue
7/29/95	10:20 a.m.	37	105.7	38.0	42.2	53	47	97	3
7/29/95	10:46 a.m.	39	100.3	38.9	45.6	40	60	92	8
7/29/95	10:54 a.m.	39	100.3	39.9	45.4	38	62	99	1
7/29/95	11:03 a.m.	42	93.1	35.6	46.3	52	48	92	8
7/29/95	11:12 a.m.	42	93.1	37.5	44.9	53	47	93	7
7/25/95	11:49 a.m.	65	60.2	31.2	41.1	50	50	88	12
7/25/95	12:01 p.m.	65	60.2	30.8	45.1	42	58	84	16
7/25/95	12:12 p.m.	65	60.2	30.4	44.1	53	47	91	9
7/25/95	12:19 p.m.	65	60.2	29.4	43.0	54	46	91	9
7/25/95	12:24 p.m.	65	60.2	29.2	48.4	47	53	93	7
8/11/95	9:46 a.m.	157	24.9	37.6	29.2	19	81	97	3
8/11/95	9:57 a.m.	157	24.9	37.2	28.8	22	78	98	2
8/11/95	10:07 a.m.	157	24.9	37.5	29.2	23	77	98	2
8/11/95	10:16 a.m.	161	24.3	36.3	34.9	24	76	98	2
8/11/95	10:21 a.m.	161	24.3	36.7	29.5	23	77	98	2
8/14/95	10:12 a.m.	311	12.6	44.4	18.2	9	91	91	9
8/14/95	10:18 a.m.	312	12.5	44.0	18.4	8	92	97	3
8/14/95	10:30 a.m.	313	12.5	44.8	17.6	7	93	95	5
8/14/95	10:34 a.m.	313	12.5	44.7	18.1	7	93	94	6
8/14/95	10:38 a.m.	313	12.5	44.3	18.3	8	92	94	6
8/18/95	11:00 a.m.	595	6.6	35.3	9.7	2	98	81	19
8/18/95	10:46 a.m.	616	6.4	35.4	6.8	2	98	98	2
8/18/95	10:50 a.m.	616	6.4	35.2	9.4	2	98	91	9
8/18/95	10:53 a.m.	616	6.4	35.0	7.3	2	98	99	1
8/18/95	10:57 a.m.	616	6.4	35.7	10.0	2	98	97	3

of repeated measurements had colorfulness values that deviated much more than 2 sigma from the exponential line. However, the spread of these values about the mean was about the same as other observations for the same optical depth. This shows that the variability in the colorfulness numbers is not affected by systematic observer bias in the average colorfulness, and that the variability will be used to define the JND. The observations of the same target by the other observer are discussed in detail below.

Table 1 gives the results of five sets of repeated matches by observer Mahadev for the roof of a red barn about 3.5 km distant. Table 1 is sorted by the extinction coefficient so that one can easily see that the perceived hue did not change with increasing haze, but that the hue derived from the spectrum changed from red to blue. Colorfulness had the opposite behavior; the perceived values decreased with increasing haze and the values from the spectrum stayed about the same. Two-way analysis of variance was applied to estimate the random error in the sets of repeated measurements in Table 1. This analysis was repeated for both observers' matches of five additional natural targets. The results are given in Table 2. The standard deviation for both observers was 2.05, as calculated from the average of the variances. Although viewing conditions were chosen to be constant, some of this variability was due to small changes in atmospheric conditions.

Based on these results, one can define the JND in colorfulness in many ways. One appropriate definition for this application is based on the following thought experiment. An observer matches a target with the visual colorimeter and determines the colorfulness to be C_1. The extinction coefficient of the atmosphere is decreased, so the colorfulness of the target is increased by an amount ΔC. The observer matches the target again to get the new colorfulness C_2. A JND is defined as the value of ΔC that gives a 95% probability that $C_2 - C_1 > 0$. Assume that C_1 and C_2 are normal random variables with standard deviation s and means C_0 and $C_0 + \Delta C$, respectively (statistical analysis of the SEAVS color matching data confirms that this is a good assumption). Then $C_2 - C_1$ is a normal random variable with mean ΔC and standard deviation $2^{1/2}\sigma$. The value of ΔC needed to ensure a 95% probability that $C_1 - C_2 > 0$ is given by $2^{1/2}\sigma F(0.95)$, where $F(0.95)$ is the inverse of the cumulative standard normal distribution and is equal to 1.645. Thus, the colorfulness JND is taken to be $2^{1/2}\sigma F(0.95) = 2.326\sigma$. From Table 2, using the data for both observers gives $\sigma = 2.05$, and a 1 colorfulness JND is 4.8. This value of σ includes the effects of small random variations in natural illumination, which should be included for this application because they are inevitably present, but makes the value of a colorfulness JND a bit larger than it would be otherwise.

Table 2. Standard deviations of colorfulness for repeated matches of natural targets.

Target	Observer M	Observer U	Distance (km)
White silo	0.91	1.33	3.54
Red roof	1.93	2.41	3.54
Near green meadow	2.93	2.15	3.86
Green hills	2.15	3.46	5.15
Far green meadow	1.45	1.64	10.46
Horizon sky	1.53	1.19	
Average	1.92	2.17	
Number of observations	55	60	

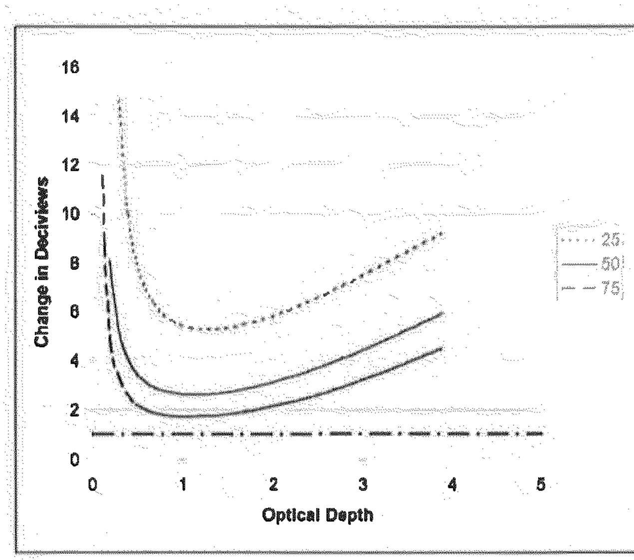

Figure 2. Change in deciviews needed to produce a just-noticeable increase in colorfulness for objects with an inherent colorfulness of 25, 50, and 75. The horizontal dashed dotted line represents what would be expected if a 1-deciview change were actually a uniform measure of haze perception.

Deciviews and Colorfulness JNDs

Relationships between colorfulness, deciviews, and optical depth are derived below; these will be applied to test the validity of the properties of deciviews given in the regional haze regulations.

From eqs 2 and 3, an expression for deciviews v as a function of colorfulness M is derived:

$$v = 10\ln\left(-\frac{1}{10x}\ln\left(\frac{M}{M_0}\right)\right) \qquad (4)$$

For a given optical depth and inherent colorfulness, the equations above were used to calculate the change in deciviews needed to give a 1-JND increase in colorfulness, using 4.8 as a JND. Figure 2 is a plot of the results as a function of optical depth for objects with three levels of inherent colorfulness. These levels of inherent colorfulness represent a reasonable range for natural targets.[12] As might be expected, more colorful objects are more sensitive to changes in atmospheric haze. Perhaps unexpectedly, the figure shows that landscape features at a distance corresponding to an optical depth of 1–2 are the most sensitive to changes in extinction as measured by deciviews. This range corresponds to one quarter to one half of the visual range. Landscape features outside this range are much less sensitive to changes in haze. If the deciview scale were perceptually uniform, as claimed in the regional haze rules, then the lines in the figure would be horizontal, or at least approximately so. However, the change in deciviews needed to produce a 1-JND change in colorfulness varied a great deal with optical depth and inherent colorfulness. The figure also shows that a 1-JND change in colorfulness always requires more than a 1-deciview change, sometimes much more.

DISCUSSION AND CONCLUSIONS

Regional atmospheric haze affects visibility by producing a visible haze layer that limits the visual range, reduces contrast, and deceases the colorfulness of objects seen though the haze. Of these three effects of haze, the decrease in colorfulness may be the most important and sensitive visual cue. Visual range is not often useful for judging the effects of small changes in extinction. For example, a change in visual range from 50 to 60 km will not be noticed if the most distant landscape feature is at 25 km. The effect of haze on contrast is a better candidate as an indicator of change in haze; however, perceived contrast, like perceived hue, is affected in a nonlinear fashion by the semitransparent nature of haze and is not a sensitive indicator of changes in atmospheric haze.[16] Experimental data have shown that colorfulness is a sensitive measure of changes in haze, so this article has used it to define just-noticeable changes in atmospheric haze.

A just-noticeable decrease in atmospheric haze is defined as a decrease in extinction that would produce a 95% probability of a measurable increase in colorfulness of an object seen through the haze. From the experimental evidence from the two young male observers, a JND in colorfulness was 4.8. For the population in general, this number is certainly too low, since all visual functions decline with age. Thus, the conclusions below about the deciview scale based on this number are understated for the general population.

Analysis of the experimental data showed that for a JND in atmospheric haze as defined above:

(1) The deciview scale is not uniform in perception over a wide range of visibility conditions. In fact, the change in deciviews needed to be noticeable

varies greatly depending on the optical distance of the landscape feature and its inherent colorfulness.

(2) A 1-deciview change is never noticeable.

What are the implications of these results for measuring progress toward reducing regional haze using the deciview metric? This is difficult to judge because the current proposals are very complex, using particulate measurements and relative humidity to estimate the extinction coefficient and average deciviews for the 20% most-impaired and 20% least-impaired days. The goal is to show no change on the least-impaired days and improvement on the most-impaired days, leading to natural conditions by 2064.[17]

The results of this article highlight a possible flaw in this regulatory scheme based on the deciview metric. An unstated assumption is that the nature of the scenic vista can be ignored—that is, a given deciview change will affect the perception of all landscape features in all scenes in the same way. Figure 2 shows that this is approximately true only if all the important landscape features have nearly the same inherent colorfulness and are at distances that correspond to an optical depth of between 1 and 2, or about one quarter to one half of the visual range. In this limited case, the deciview is indeed a uniform metric. However, most scenic vistas do not fit these restrictions and, by Figure 2, will require greater decreases in extinction as measured by deciviews to show a perceptible change. The result is that the emission reductions required by the proposed regulatory analysis are likely to produce much smaller improvements in perceived effects of regional haze than expected. The EPA guidance documents provide an example of an eastern scenic vista with a baseline of 27 deciviews and natural conditions of 11.[17] The decrease in extinction to reach natural conditions by 2064 is 0.35 deciview/yr, or 1.75 deciviews in five years. This five-year reduction should, according to the regulations, result in a noticeable change in regional haze. However, the results herein predict that there would very likely be no noticeable difference in any actual scenic vista in the region as a result of the required emission reductions.

Regional haze rules also call for a uniform rate of improvement in visibility (measured in deciviews) that is needed to go from current conditions to natural conditions by 2064. Since the deciview scale is not uniform in perception over a wide range of visibility conditions, this requirement is also flawed and will not result in uniform improvement in perceived visibility.

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About the Author

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TANGENTIAL LOW NOx (TLN3) SYSTEM
FOR

ENTERGY
WHITE BLUFF UNITS 1& 2

Proposal No. 65-130582-00 Rev. 0
October 13, 2011

Exhibit F to EAI Comments

PROPIETARY AND CONFIDENTIAL INFORMATION

This proposal and the information, design and material contained and/or illustrated herein (hereinafter "proprietary and confidential" material), are the property of FOSTER WHEELER NORTH AMERICA CORP, (FWNAC) and is submitted, lent and furnished to you in the strict confidence with the expressed understanding that you shall not use said proprietary material for any purpose other than for the evaluation of this proposal or reproduce, copy, lend, dispose of, or disclose said proprietary material to anyone outside receipt organization. By receiving said proprietary material you agree not to use the same in any way injurious to the interest of FOSTER WHEELER NORTH AMERICA CORP, and agree to return to same upon request.

3.3 Foster Wheeler's Tangential Low NOx (TLN) Systems

3.3.1 Design Philosophy

Foster Wheeler North America Corp's (FWNAC) Tangential Low NOx (TLN) Combustion Systems provide industrial and utility boiler owners with an alternative solution to their NOx compliance needs. Our philosophy is to provide our clients with the highest value low NOx system.

- Our systems are designed to maximize NOx reduction efficiency while minimizing the impact on combustion performance or unit operation. An extensive support team of experienced technical and project specialists backs our commitment.

- We focus on designing systems that minimize changes to the furnace and / or the boiler house. This reduces installation time and costs for the owner.

- We believe each TLN application should complement the unit's operational capabilities as well as the range of current and future fuels.

- We believe that each TLN system should provide years of reliable service. All T-fired windbox components are manufactured in either our own facilities or per our specifications by high quality suppliers.

- A team of experienced and qualified tangential firing engineers, project managers, service engineers and suppliers supports each project. Our goal is to make each of your TLN retrofits your most favorable project.

Our system technology is supported by a continuous commitment to improve performance and reliability. For example our on-line real-time, ECT coal flow distribution, velocity and particle size monitoring technology combined with our CADM system allows fuel and air to be more balanced for lower CO and higher combustion efficiency.

Currently there are numerous tangentially coal fired utility units equipped with Foster Wheeler's TLN systems (see Experience List in Appendix). Fuels being fired range from lignite and PRB through low and higher sulfur eastern bituminous coals. NOx reductions exceeding 70 percent and NOx levels below 0.10 lb/MBtu are being achieved.

3.3.2 FWNAC's TLN Systems

Foster Wheeler's Tangential Low NOx (TLN) firing systems are based on the application of secondary air staging technology commonly referred to as "overfire air". Both in-windbox and separated secondary air-staging arrangements are applied depending on current windbox configurations and the desired level of NOx reduction. Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is reduced. Control of this staging process through proper nozzle and damper design is critical in order to maximize combustion efficiency and component longevity. Depending on the unit configuration and required NOx reductions, Foster Wheeler can offer several high value options. These include the TLN1, TLN2 and TLN3 arrangements, which are shown below in **Figure 3.**

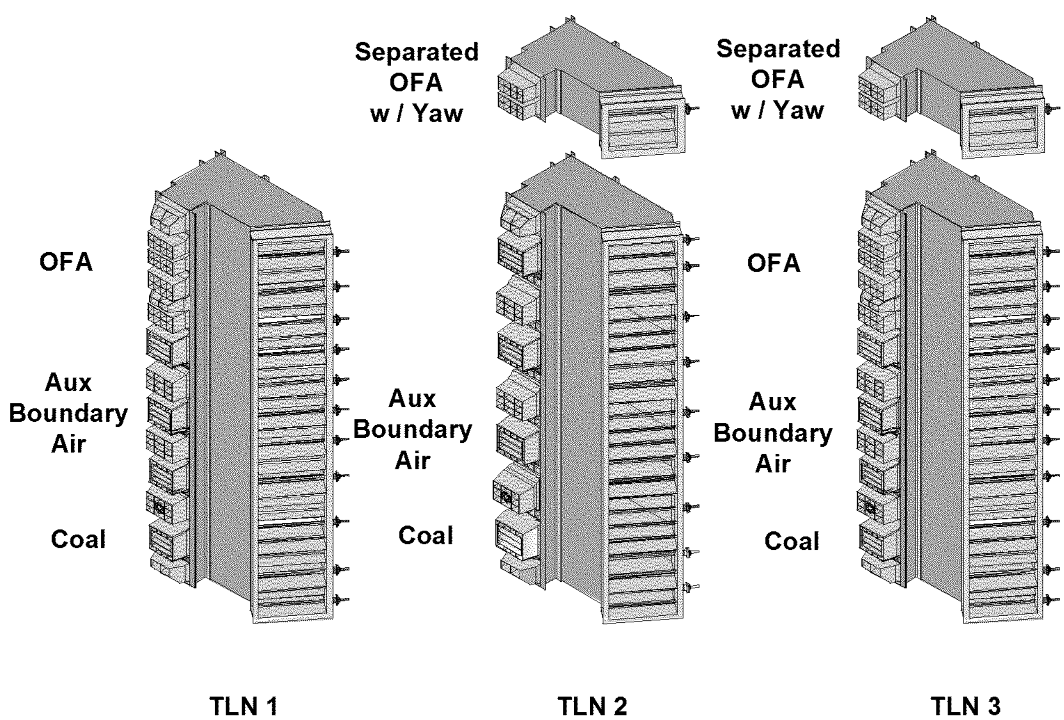

Figure 3 - FWNAC Tangential Low NOx (TLN) Configurations

Foster Wheeler's **TLN2** system consists of adding a single level of separated overfire air above the main firing zone to provide the required vertical air staging effect. Due to increased spacing from the upper coal elevation, separated overfire arrangements provide significantly higher NOx reduction efficiencies as compared with "in-windbox" arrangements. Nozzle tips and/or air flow control dampers in the main windboxes are often resized or modified as part of such retrofits. Foster Wheeler's proprietary computer-modeling program is used to ensure that proper airflow distribution control and air/coal mixing is maintained throughout the unit load range with the new SOFA addition.

The **TLN3** system consists of adding a single level of separated overfire air to units that already have an in-windbox OFA. Other applications of the TLN3 arrangements are units where interferences do not permit placement of an adequate single overfire air windbox level. Nozzle tips and air flow control dampers in the main windboxes are often upgraded or modified in accordance with computer modeling results or to meet specific unit or fuel requirements. These modifications ensure that proper airflow distribution control and air/coal mixing is maintained. Both the TLN2 and TLN3 have demonstrated up to 75% NOx reduction.

3.3.3 Combustion Computational Fluid Dynamics - Option

Foster Wheeler is offering a Computational Fluid Dynamics (CFD) study of furnace thermodynamics to validate boiler performance before and after installation of the SOFA system. CFD analysis is an inherently man-hour intensive process because the ability of the CFD model to provide accurate predictions is predicated on the accuracy of the model and thus requires that each existing system (boiler) be manually detailed in the program prior to use. CFD can therefore be a somewhat expensive undertaking.

FWNAC feels obligated to inform Entergy that the results of CFD modeling have never altered the design, predictions or guarantees associated with a TLN retrofit and can therefore be somewhat of an extraneous exercise unless applied to validate a specific, unique design feature. In other words, should Entergy find the cost/benefit associated with use of CFD to be less than satisfactory, solace should be found in the fact that it will only service to confirm the design being offered.

Should Entergy desire to proceed with use of Foster Wheeler's Combustion CFD program, on both White Bluff units, the model will extend from the burner fronts up through the leading edge of the first bank of the finishing superheater.

Vital to any OFA design is full penetration of the air jets into the furnace gas stream to insure turbulent mixing with the bulk of the rising flue gases. This is accomplished by choosing appropriate nozzle velocities and sizes. Foster Wheeler has studied jet

4 DESCRIPTION OF PROPOSED FWNAC TLN3 SYSTEM

4.1 Proposed TLN3 System for White Bluff Units 1 and 2

Based on Entergy's requirements and FWNAC's evaluation of the current unit operation, FWNAC is proposing our TLN3 system. This system will consist of the following specific components and features.

The proposed FWNAC modifications to Entergy's White Bluff Units 1 and 2 are shown on FWNAC proposal drawings attached in the Appendix.

a) A SINGLE level of new separated SOFA windboxes will be provided as part of the FWNAC TLN3 system. This would consist of eight (8) new SOFA windboxes. To minimize physical changes to the boiler house, the new Overfire Air windboxes would be installed in the front and rear walls above the existing windboxes. The SOFA windboxes would be designed to supply the appropriate amount of combustion air as Overfire Air. Each new windbox will be provided along with new water wall panels and the necessary connecting ductwork, hangers, expansion joints and steel modifications to interface with the secondary air ducts. Each windbox will be fitted with nozzle tips, turning vanes, access doors, air control dampers with actuators (Kinetrol 147-130-1900 Fail Open Spring return Actuator with Siemens PS2 Single Acting Smart Positioner) and static pressure taps to provide total Overfire Air control. Manual "set and forget" horizontal yaw and vertical tilt capability would be provided in the SOFA to help control CO as well as back end gas temperature and oxygen profiles. The yaw linkage, manual tilt gearbox and damper drives will be accessible from the sides of each windbox.

   A CFD air flow model will be developed that includes the secondary air ducts, SOFA ducts, windboxes and burners to ensure balanced air flow.

b) Platform, railing, sootblowers, and sootblower piping may need to be modified where required to accommodate the addition of the separated over fire air system.

c) New FW Double Shroud (DS) type nozzle tips and associated linkage hardware will be supplied. These will be 100% compatible with the existing coal nozzle and tilt linkage. The new nozzle tip, which includes a patented (US Patent No. 6,260,491) cooling feature, will also be reconfigured to further help stage more air to the SOFA compartments to provide additional NOx reduction benefits.

d) The 23¼ inch high upper CCOFA compartment will be modified with a crotch cooling plate on the top and a restrictor plate on the bottom to reduce the outlet height to 19 ¼ inches. A new, one piece FWNAC DS style nozzle tip will be provided. This tip will be the same tip as the lower CCOFA and bottom air tips. This interchangeability will reduce stocking and maintenance costs.

e) The 23¼ inch high lower CCOFA compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the upper CCOFA nozzle tip.

f) The fuel piping to the refuse compartment is currently blanked off, with no future plans for firing this compartment. As a top end air, this 24 inch high compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the CCOFA nozzles.

g) The outlet flow area of each 27¼ inch high auxiliary air compartment will be reduced with restrictor plates for velocity compensation. Each compartment will be fitted with one (1) new, one piece FWNAC DS style type boundary air auxiliary nozzle tip. The nozzle tip is designed to provide the necessary velocity, air flow distribution and direction control to benefit NOx emissions and fireball shaping while maximizing combustion efficiency.

h) The 27¼ inch high oil warm-up compartment will also be reduced with restrictor plates for velocity compensation and modified with a similar tip, with the center of the tip to accommodate the existing oil gun. However, due to the presence of the oil warm-up gun, this tip will not yaw.

i) The existing bottom end air compartments will be fitted with new, one piece reduced free area nozzle tips. These tips will be interchangeable with the CCOFA tips.

j) As an integral part of the TLN3 system, the Lower Furnace Stoichiometry Control (LFSC) system will be provided. These systems help reduce the dark lower furnace hopper conditions typically associated with deep-staged combustion systems. It is comprised of a single air nozzle tip with external manual tilt installed in the bottom end air compartment. This will be used to direct combustion air into the lower furnace hopper area, further controlling lower furnace smoky conditions, slagging and CO formation that might occur during ultra low NOx deep staged operation.

k) All coal, auxiliary air and CCOFA windbox compartments will be modified with FWNAC's damper venturi plates to improve air flow distribution control over a larger load range.

7 PERFORMANCE GUARANTEES& CONDITIONS

7.1 Performance Guarantees

The following Performance Guarantees contained within this section 7.1 are the **exclusive performance guarantees** offered by FWNAC relating to the equipment supplied by FWNAC. Any graphs, stated performance values, predictions or discussions in other sections of the proposal or in the specification fill-in sheets shall not be construed as performance guarantees.

- Three (3) one hour tests will be conducted for NOx, CO, LOI, main steam temperature and reheat steam temperature at MCR. Three (3) one hour tests will also be conducted for main and reheat steam temperatures at Guarantee Point Load and Control Load. The guarantees will be considered met if the average of each guarantee value over the three (3) test periods meets the guarantee values offered below by FWNAC.

  A thirty (30) day rolling average test will also be conducted for NOx and CO emissions. This test may be conducted for 45 day period to allow for selection of the data for the 30 day period. Only data to be included will be that while the unit is operating between Control Load and MCR. Data will be excluded while the unit is at upset condition.

- All performance conditions, test methods, and referenced fuels/ranges of fuels as defined in Section 7.2 of this proposal are considered a prerequisite for the guarantees. All sampling must ensure that a representative average of the flue gas emissions and fly ash sample is taken.

7.1.1 NOx Emissions

<u>MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.12 lb/MBtu for the average of three (3) one hour tests**

<u>Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.14 lb/MBtu over a 30 day period**

7.1.2 Carbon Monoxide (CO)

MCR (6,023 klb/hr main steam flow)

ffi **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) for the average of three (3) one hour tests**

Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)

ffi **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) over a 30 day period**

7.1.3 Fly Ash LOI

MCR (6,023 klb/hr main steam flow)

ffi **Fly ash LOI will average less than or equal to 1.0% for the average of three (3) one hour tests**

7.1.4 Superheat (SH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

ffi **980 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

ffi **980 ±10°F** for the average of three (3) one hour tests

Control Load (3,000 klb/hr main steam flow)

ffi **980 ±10°F** for the average of three (3) one hour tests

7.1.5 Reheat (RH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

ffi **1000 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

July 30, 2015
Ref: Tangential Low NOx

Michael P. Fallon, P.E.
Entergy – Boiler Process Owner
White Bluff & Lake Catherine

Dear Mike;

Tangential low NOx systems that use separated overfire air are designed to provide significant reductions in NOx across the control range of the boiler, which is normally from 50 to 100 percent of steam flow. These systems work in the control range because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers. When this is done combustion zone airflow is sub stoichiometric and oxygen there is reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without oxidizing.

Overfire air cannot be fully utilized for NOx abatement below the control range because net heat input is not sufficient to allow the combustion zone in the furnace to safely run in a sub stoichiometric condition. When a boiler runs below the control range NOx concentrations can be elevated above the levels achievable at higher loads, even though the tons of NOx emitted is less due to the reduced amount of fuel and air.

I hope this memo answers your question.

Steve deMello
Project Manager
Amec Foster Wheeler North America Corp.
53 Frontage Road, PO Box 9000
Hampton, NJ 08827-9000

EVALUATION OF THE CALPUFF MODELING SYSTEM MARGIN OF ERROR FOR A BART ANALYSIS

Entergy Arkansas, Inc. > Lake Catherine Plant

Entergy
THE POWER OF PEOPLE

Prepared By:

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August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit H to EAI Comments

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. As part of the FIP, EPA proposed nitrogen oxide (NO_X) controls for the Entergy Arkansas, Inc. (Entergy) Lake Catherine Plant Unit 4, which is subject to Best Available Retrofit Technology (BART).[1] In order to justify the visibility improvement as a result of installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system (CALPUFF) without assessing the reliability of the model to predict small changes in visibility.

Entergy completed a quantitative analysis to evaluate the margin of error in the CALPUFF analysis for Lake Catherine Unit 4 and determined the visibility improvements relied upon in the proposed Arkansas FIP are within the model's margin of error. Specifically, the incremental visibility improvements predicted by CALPUFF at the Caney Creek Wilderness Area (Caney Creek) and Upper Buffalo Wilderness Area (Upper Buffalo) Class I areas are within the margins of error calculated for each Class I area. Moreover, the visibility improvement values are within the *lowest* margin of error for both Class I areas. Because of this, EPA cannot *reasonably anticipate* visibility benefits from the proposed controls for Lake Catherine Unit 4. *See National Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1146□47 (9th Cir. 2015) ("Montana Case") (holding that EPA must offer a reasoned explanation of its conclusion that a visibility improvement could be reasonably anticipated when the improvement is within CALPUFF's margin of error).

This report is organized as follows: Section 2 provides background on the Lake Catherine Plant and EPA's proposed BART requirements, Section 3 outlines the methodology used in the Lake Catherine analysis, Section 4 summarizes the results of the analysis, and Section 5 presents several case studies comparing modeled values to monitored values.

[1] Proposed Arkansas Regional Haze FIP, 80 Fed. Reg. 18,943 (Apr. 8, 2015).

2. BACKGROUND

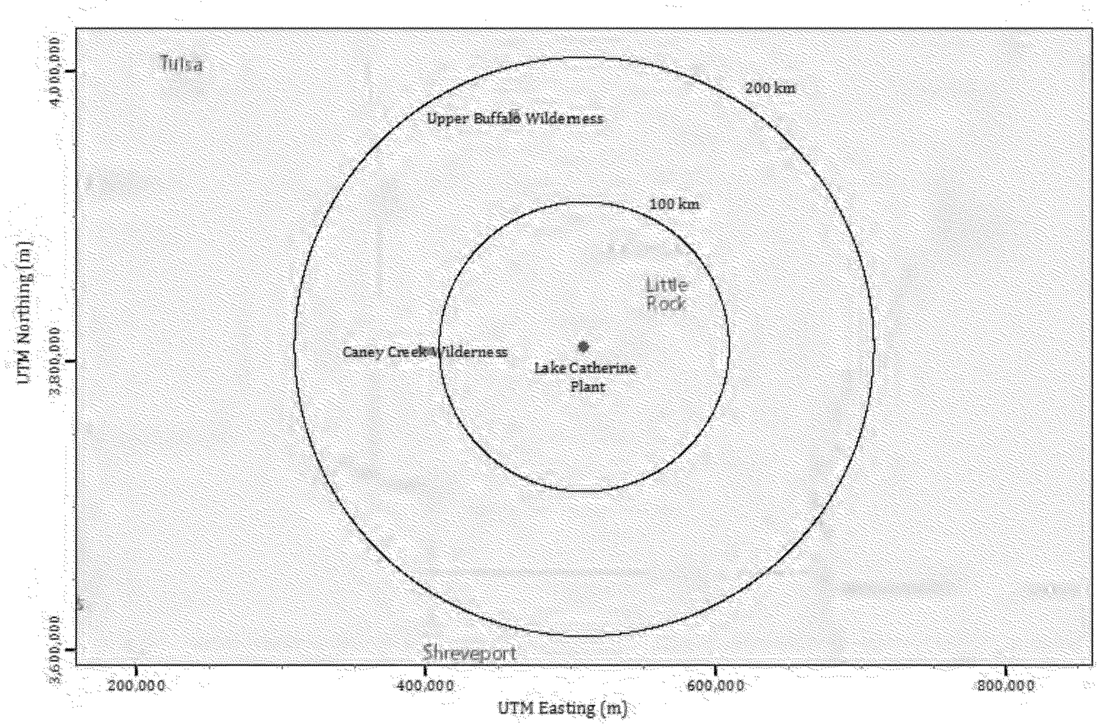
Entergy owns and operates the Lake Catherine Plant located at 141 W. County Line Road in Malvern, Arkansas. The Lake Catherine Plant operates one emission unit – Unit 4 – that is an affected source under the BART provisions of the EPA's Regional Haze Rule, which is codified in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. Unit 4 is a tangentially-fired boiler with a nominal heat input rate of 5,850 Million British thermal units per hour (MMBtu/hr) and a nominal net power rating of 558 megawatts (MW). The boiler is permitted to fire natural gas and No. 6 fuel oil; however, the unit has not fired fuel oil since the 2001-2003 baseline period and Entergy does not plan to burn fuel oil in the unit in the foreseeable future.

On April 18, 2015, EPA proposed a FIP to address requirements related to regional haze for those portions of the Arkansas State Implementation Plan (SIP) that were disapproved on March 12, 2012.[2] The FIP includes NO_X BART requirements for Lake Catherine Unit 4.

2.1. CLASS I AREAS

Per the FIP, there are two (2) Class I areas in Arkansas that are impacted by Unit 4 at the Lake Catherine Plant: Caney Creek and Upper Buffalo. Caney Creek is approximately 100 km west and Upper Buffalo is approximately 160 km north of the Lake Catherine Plant. The locations of the Class I areas with respect to the Lake Catherine Plant are shown in Figure 2-1 below. Table 2-1 summarizes the baseline visibility impairment attributable to Unit 4 at each of these Class I areas as determined by CALPUFF.[3]

Figure 2-1. Location of Lake Catherine Plant with Respect to Arkansas Class I Areas



[2] FR Vol. 80, No. 84, May 1, 2015.

[3] Ibid.

Table 2-1. Baseline Visibility Impairment

Emission Unit		Caney Creek	Upper Buffalo
Unit 4	Maximum (Δdv)[1]	3.480	2.044
	98th Percentile(Δdv)[1]	1.371	0.489

1. Values shown are for natural gas combustion.

2.2. PROPOSED BART FOR THE LAKE CATHERINE PLANT

The proposed NO_X BART for Lake Catherine Unit 4 is summarized below.

2.2.1. NO_X BART

In the proposed FIP, EPA determined that NO_X BART for Unit 4 for the natural gas scenario is an emission limit of 0.22 pounds per MMBtu (lb/MMBtu) on a 30 boiler-operating-day rolling averaging basis, based on the installation and operation of Burners out of Service (BOOS).[4] The projected visibility improvement at Caney Creek and Upper Buffalo based on CALPUFF modeling is shown in Table 2-2 below.

Table 2-2. Projected Visibility Improvement

Emission Unit	Pollutant	Caney Creek (Δdv)	Upper Buffalo (Δdv)
Unit 4	NO_X	0.596	0.248

[4] Per the FIP, "BOOS is a staged combustion technique in which fuel is introduced through operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners."

3. MODELING METHODOLOGY

In completing the BART five factor analysis for Lake Catherine Unit 4, EPA relied on the visibility improvement as predicted by CALPUFF without assessing the ability of the model to accurately predict small changes in visibility. In order to assess the magnitude of visibility that could reasonably be anticipated for the Lake Catherine case, Trinity conducted a margin of error analysis similar to the one completed for the Colstrip Generating Station ("Colstrip Station") by TRC Environmental Corporation (TRC) that was the basis for PPL Montana's comments on the CALPUFF model in the Montana Case.[5] The following sections outline the methodology that was used to complete this analysis for the Lake Catherine Plant. This study is necessary due to the dissimilarities in the geographical and meteorological conditions between the Lake Catherine Plant and the Colstrip Station at issue in the Montana Case.

3.1. MODEL SELECTION

The BART Guidelines recommend using the CALPUFF Modeling System to determine the visibility impairment attributable to a BART-eligible source. This analysis was completed using CALPUFF Version 5.84, POSTUTIL Version 1.52, and CALPOST Version 6.221, the model versions utilized in the Arkansas BART analyses. Entergy used refined meteorological data consistent with the meteorological data used for other BART sources in Arkansas. On July 26, 2012, the Arkansas Department of Environmental Quality (ADEQ) updated its original (June 7, 2006) protocol including CALPUFF modeling components and the background concentrations in CALPOST. The CALMET data and parameters are based on the modeling protocol that was first submitted on January 23, 2008 on behalf of Oklahoma Gas & Electric and upon which all recent BART analysis in Arkansas have been based. This protocol summarizes modeling methods and procedures that were followed to predict visibility impairment for several BART-eligible sources located in Oklahoma as part of the BART analyses for these sources.

3.2. MODELED SCENARIOS

As part of this analysis Entergy modeled the following three scenarios:

1. ALL BART: Includes all sources subject to BART modeled using Pre-BART representations;
2. Pre-BART: Includes only the Lake Catherine Plant BART eligible source modeled based on its current permit representations; and
3. Post-BART: Includes only the Lake Catherine Plant BART eligible source modeled using the Post-BART emission rate and stack parameters.

3.3. BACKGROUND VALUES

The primary objective of this analysis was to compare the model predicted data to monitored data at each Class I area to identify the modeling margin of error in predicting visibility compared to observed values. BART modeling using CALPUFF is conducted to determine the impact of a facility on a Class I area without consideration of emissions/impacts from other sources. This type of analysis uses only natural background

[5] *See* "Accuracy of Visibility Protocol Modeling in BART Evaluations" prepared by Gale F. Hoffnagle, TRC Environmental Corporation, June 15, 2012. PPL Montana relied on this analysis in its comments alleging that the incremental visibility improvement predicted by EPA at Colstrip Station were within CALPUFF's margin of error. *See* PPL Montana, LLC's Comments on Proposed Regional Haze Federal Implementation Plan for the State of Montana at 8-11, Docket ID EPA-R08-OAR-2011-0851-0211 (2012).

conditions, referred to by EPA as a "clean background" analysis. As such, comparing model predicted output directly from the CALPUFF Modeling System to monitoring data does not represent a like-kind comparison as it is missing contribution from other sources. In order to obtain an estimate of the impact of other emission sources (i.e., point, non-point, mobile, biogenic, etc.), Entergy obtained a background value from CAMx modeling completed for the Central Regional Air Planning Association (CENRAP) by ENVIRON using the CENRAP PM Source Apportionment Technology (PSAT) Tool.[6] The CENRAP's CAMx analysis was completed for actual emissions from 2002; therefore, the background value from 2002 was added to the CALPUFF predicted impacts for all modeling scenarios and compared to 2002 IMPROVE data for Caney Creek and Upper Buffalo.

3.4. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Entergy calculated the average difference between modeled values obtained using the CALPUFF Modeling System (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three (3) modeling scenarios described previously. Unlike BART analyses where the 98th percentile values are compared to the dv impact level, Entergy utilized the regional haze design value format of average worst 20% days for this analysis. Since the CENRAP background value is from the 2002 calendar year, this comparison was only completed for 2002. Specifically the following comparisons were made:

- Modeled vs Measured 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.
- Measured vs. Modeled 20% Worst Days: The worst 20% days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.
- Measured and Modeled 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected and compared with the worst 20% days based on CALPUFF modeling results disregarding temporal correlation.

Entergy used these average differences to determine the lowest overall margin of error for each Class I area. Entergy also examined how the modeled visibility impacts from the Lake Catherine Pre-BART scenario, excluding background, compared with the IMPROVE measurements at Caney Creek and Upper Buffalo. This provides an indication of the magnitude of the contribution from Lake Catherine Unit 4 to the total visibility impairment reflected in the IMPROVE measurements.

[6] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool - CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb

4. RESULTS

The following sections summarize the results of the analyses completed for the Lake Catherine Plant.

4.1. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Table 4-1 below summarizes the average difference between the modeled versus measured 20% worst days (20% worst-days based on measured values), measured versus modeled 20% worst days (20% worst-days selected based on modeled values), and modeled and measured 20% worst days (comparison of values from 20% worst modeled days and 20% worst measured days not temporally paired). Consistent with the study assessing CALPUFF modeling for the Colstrip Station, CALPUFF consistently over predicts when compared to IMPROVE observations.

Table 4-1. Summary of Modeled Versus Measured Statistics

Model Scenario	Modeled vs. Measured Statistics	CACR (Mm-1)	CACR (dv)	UPBU (Mm-1)	UPBU (dv)
All BART Sources	Modeled vs. Measured 20% Worst Days Average Difference	28.69	1.40	22.18	1.09
	Measured vs. Modeled 20% Worst Days Average Difference	45.64	6.47	51.65	6.09
	Modeled & Measured 20% Worst Days Average Difference	25.52	1.16	20.09	0.93
Lake Catherine Pre-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.60	1.39	21.98	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.79	5.89	64.46	7.86
	Modeled & Measured 20% Worst Days Average Difference	27.88	1.34	21.50	1.04
Lake Catherine Post-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.81	1.40	22.01	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.25	5.85	66.86	8.24
	Modeled & Measured 20% Worst Days Average Difference	28.42	1.38	21.74	1.05
	Average	**32.95**	**2.92**	**34.72**	**3.16**
	Maximum	**45.64**	**6.47**	**66.86**	**8.24**
	Minimum	**25.52**	**1.16**	**20.09**	**0.93**

The lowest calculated margin of error at Upper Buffalo is 0.93 dv. A larger margin of error, 1.16 dv, was calculated for Caney Creek. As shown in Table 4-2 below, the CALPUFF predicted visibility improvement at Caney Creek and Upper Buffalo obtained from the Arkansas FIP is within the margin of error calculated for each Class I area. Moreover, the predicted visibility improvement is within the lowest margin of error of 0.93 dv regardless of the Class I area. This analysis suggests that the formulation associated with CALPUFF forces the model to predict a value for a given scenario regardless of the accuracy of the value. Moreover, the model predicted number at these lower ranges may not necessarily result in the actual visibility improvement, as the numbers can very well be within the uncertainty in the prediction.

According to the BART guidance, use of 98th percentile or 8th highest value of model prediction is used to reduce the effect of uncertainty in the CALPUFF models. The Lake Catherine analysis uses the worst 20% days or 24 high values to determine the margin of error, thus providing additional data points for the analysis rather than just one data point (i.e., 98th percentile). The use of worst 20% days is consistent with the calculations associated with the reasonable progress goals. Use of the 98th percentile does not address the real issue, that the CALPUFF model is predicting visibility improvements for Lake Catherine that fall within the model's margin of error for this case, thus the projected visibility improvements cannot be *reasonably anticipated* as is required by the Clean Air Act. As stated in the Montana Case, "The issue is not the *perceptibility* of the proposed improvements, but the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye."[7] EPA has failed to address how CALPUFF can be used as the basis for BART determinations when the predicted visibility improvements in many cases are lower than the calculated margin of error. Due to the uncertainty in the model's ability to predict small visibility improvements, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated*.

Table 4-2. Projected Visibility Improvement from Lake Catherine Margin of Error

Emission Units	Baseline Visibility Impact (dv)	Visibility Improvement from Baseline (Δdv)	Calculated Margin of Error (dv)
Lake CatherineUnit 4			
Caney Creek Wilderness Area	1.371	0.596	1.16
Upper Buffalo Wilderness Area	0.532	0.248	0.93

[1] Data obtained from the proposed AR FIP (FR Vol. 80, No. 67) - https://federalregister.gov/a/2015-06726

[7] Montana Case, at 1147.

4.1.1. Caney Creek Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 at Caney Creek.

Figure 4-1. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

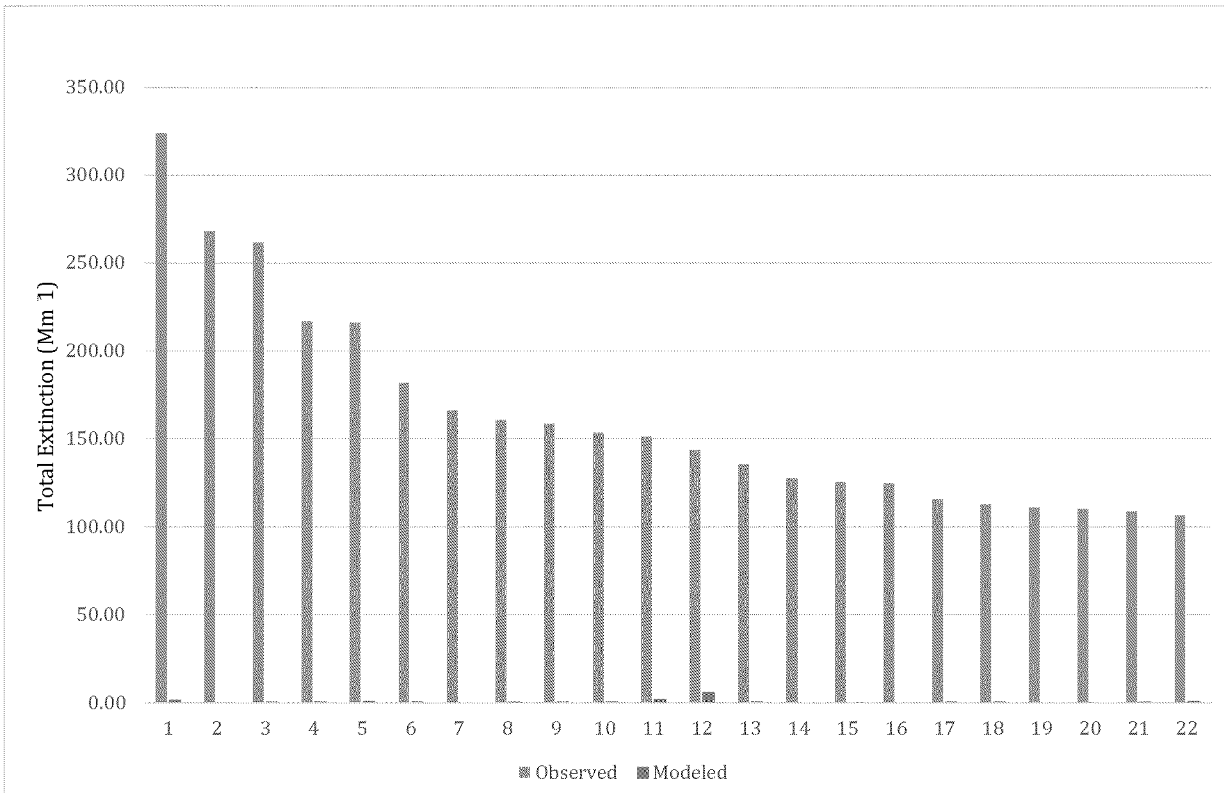


Figure 4-2. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

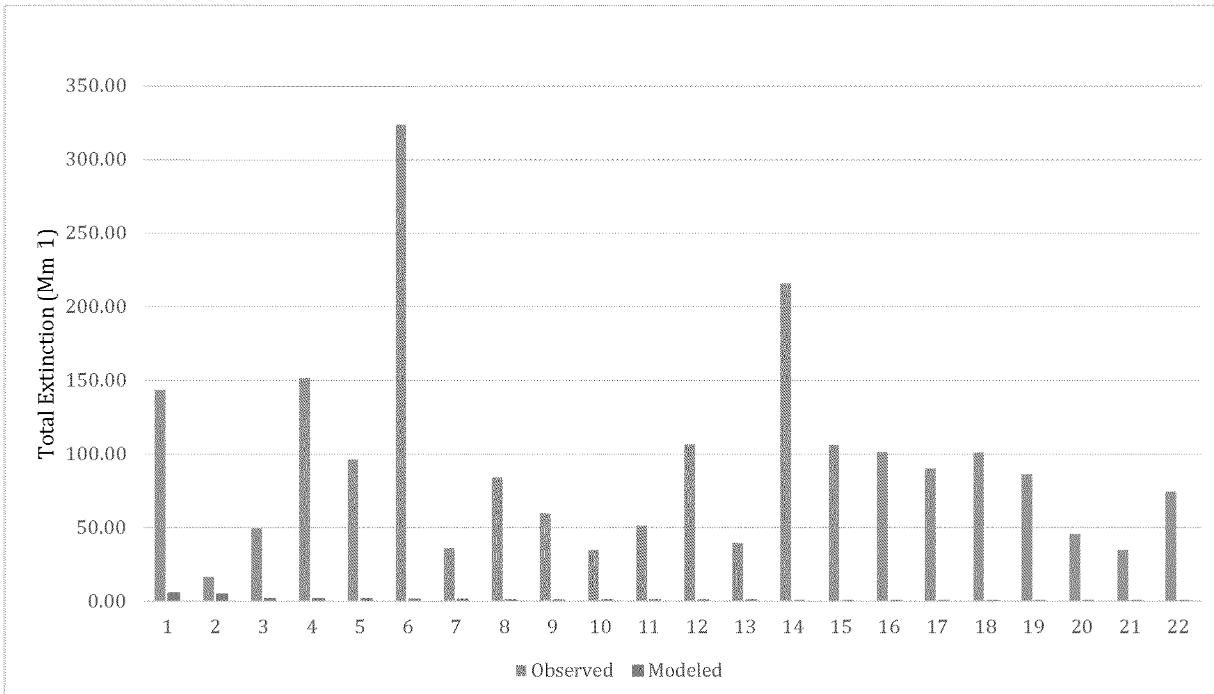
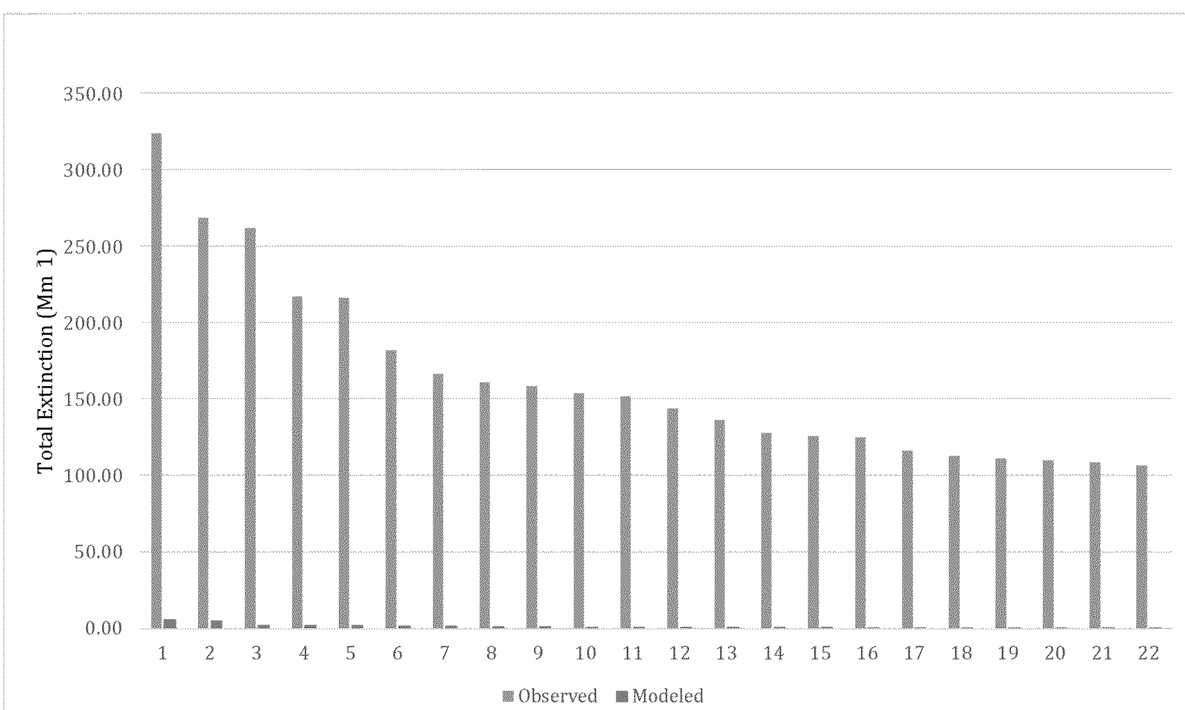


Figure 4-3. Measured and Modeled 20% Worst Days Total Extinction at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART



As demonstrated by the plots above, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine, on the Class I area. This indicates that the contribution from the Lake Catherine Plant to overall visibility impairment at Caney Creek is negligible.

4.1.2. Upper Buffalo Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 for Upper Buffalo.

Figure 4-4. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

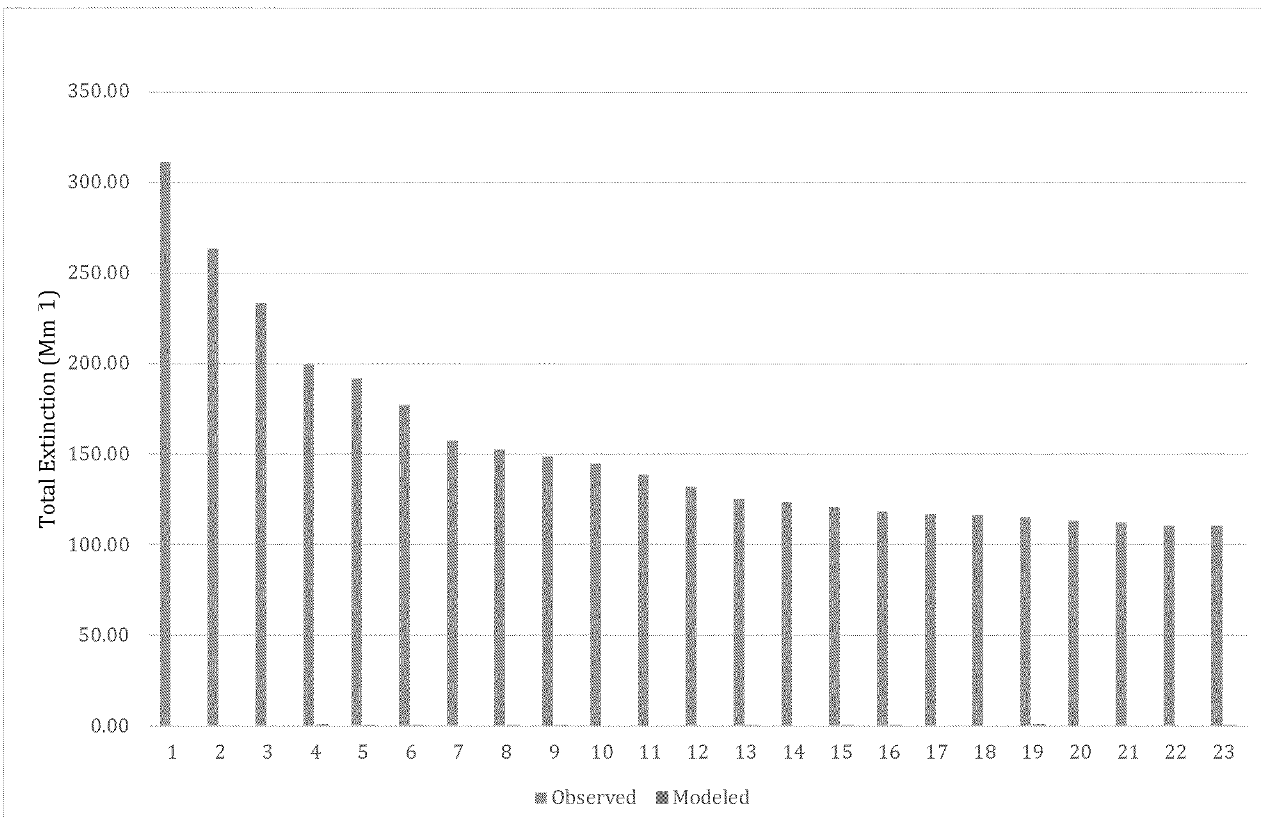


Figure 4-5. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

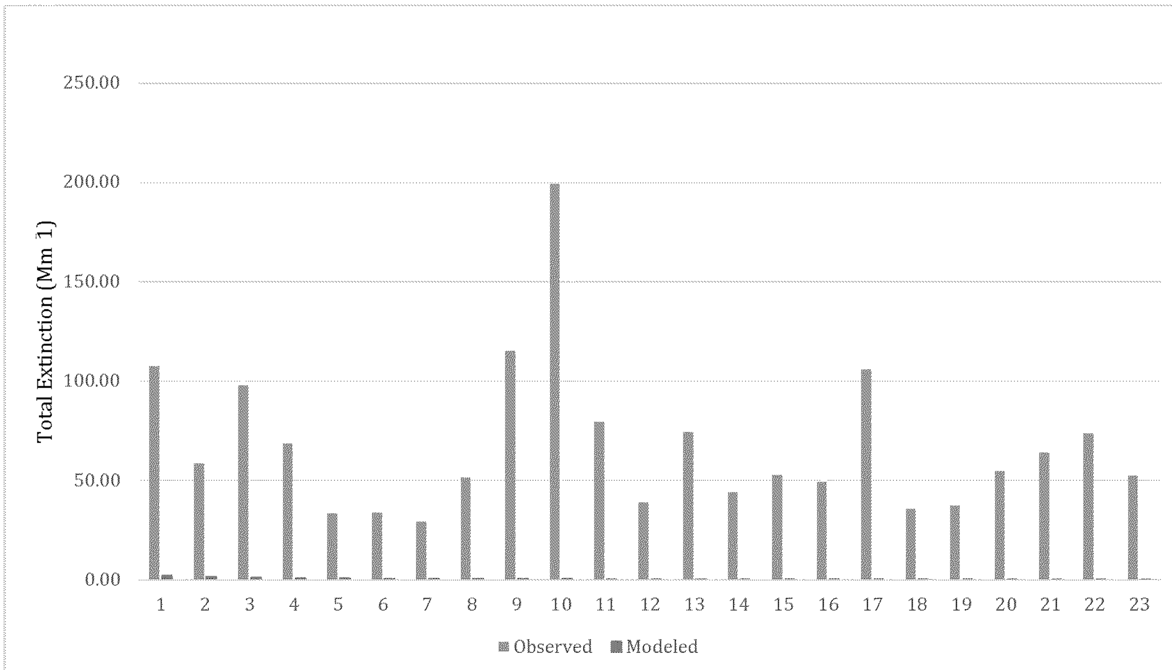
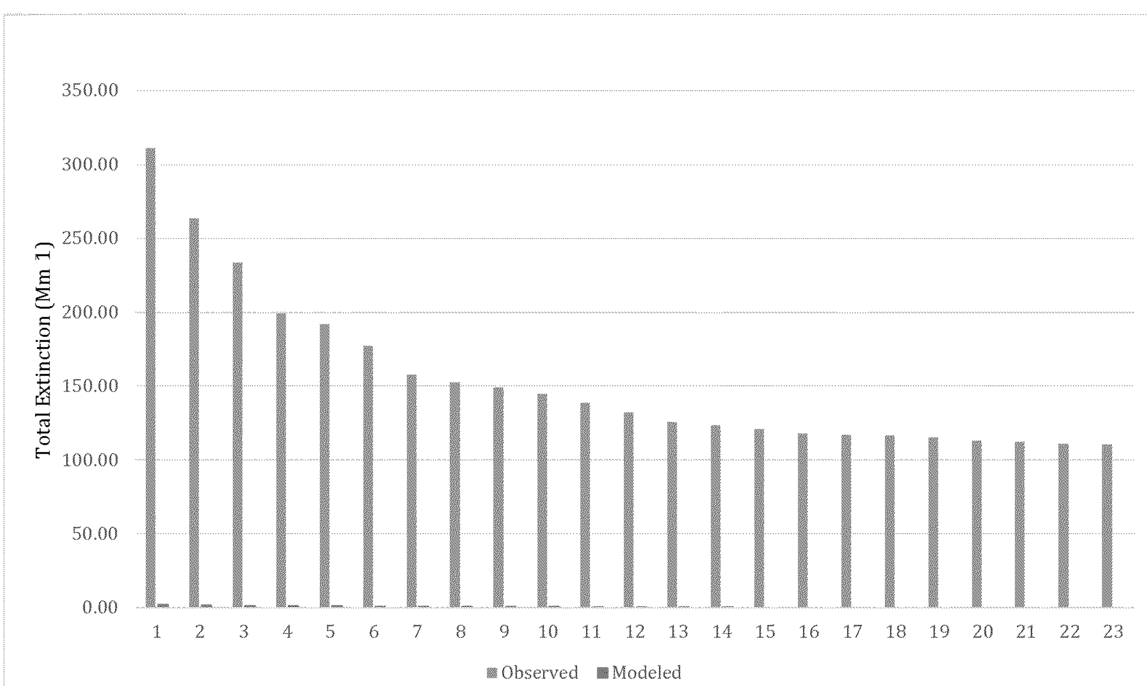


Figure 4-6. Measured and Modeled 20% Worst Days Total Extinction at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART



As was the case for Caney Creek, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine. Thus, the contribution from the Lake Catherine Plant to visibility impairment at Upper Buffalo is negligible.

5. CASE STUDIES

In June of 2012, TRC wrote a paper entitled *Accuracy of Visibility Protocol Modeling in BART Evaluations.*[8] This paper discussed several case studies comparing modeled values from CALPUFF to measured values from the IMPROVE monitoring network. PPL Montana relied on this study in its successful challenge to the Montana FIP, for its argument that EPA failed to explain why it could reasonably anticipate a visibility improvement when the improvement was within CALPUFF's margin of error.[9,10] An overview of several case studies comparing CALPUFF modeled to measured values, including the study relied upon in the Montana Case, are provided below for reference.

The CALPUFF version approved by EPA for use in BART analyses is Version 5.84, which was released on June 23, 2007.[11] Comparisons of modeled to monitored values demonstrate a significant improvement in model performance.

5.1. MOHAVE GENERATING STATION

CALPUFF modeling completed for the Mohave Generating Station (Mohave Station) showed that the 1,590 megawatt (Mw) coal-fired power plant was causing visibility impacts of 2.31 dv at the Grand Canyon National Park. The plant was permanently shut down in 2005. A review of monitored visibility at IMPROVE stations as close as 90 km to the plant showed no change in either nitrate concentrations or visibility impacts subsequent to the closure of the plant. The measured visibility impairment at the Grand Canyon National Park during the three years prior to (2003-2005) and subsequent to the permanent shutdown (2006-2008) of the Mohave Station were analyzed.[12] Based on a review of data from three (3) IMPROVE monitoring sites, summarized in Table 5-1 below, the changes in visibility were not statistically significant.

Table 5-1. Mohave Visibility Impairment – Before and After

IMPROVE Monitor	2003-2005 (dv)	2006-2008 (dv)	Difference (dv)
Meadview	8.24	8.23	0
Indian Gardens	8.92	8.86	0.1
Hance Camp	6.54	6.61	-0.14

While the actual change at the nearest monitor between pre- and post-shutdown of the Mohave Station, Meadview, was zero dv, the CALPUFF results indicated that visibility impairment caused by the Mohave Station

[8] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[9] Montana Case, at 1146□47.

[10] 42 U.S.C. 7491(g)(2).

[11] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012. Although numerous updates have been released since that time, EPA still relies on an outdated version of the model despite the fact that considerable advancements have been made. Newer versions of CALPUFF include more complex chemistry which allows for more accurate representation of sulfate and nitrate formation by considering ozone chemistry, organic aerosol formation, inorganic gas particle equilibrium, and aqueous phase transformation.

[12] Jonathan Terhorst and Mark Berkman, *Effect of Coal-fired Power Generation on Visibility in a Nearby National Park*, Atmospheric Environment 44, 2010.

was twice the level detectable by the human eye.[13] The maximum CALPUFF predicted visibility impairment was 3.94 dv over 3 years, with a 98th percentile visibility impairment of 2.31 dv from the Mohave Station. Based on the IMPROVE monitoring data, CALPUFF highly overestimated the visibility impairment attributable to the Mohave Station. In reality, the Mohave Station had essentially no impact on the visibility impairment at the Grand Canyon National Park as documented by the change in monitoring values pre- and post-shutdown.

5.2. CRAIG STATION

The Craig Station is located approximately 90 km west of the Mt. Zirkel Wilderness Area (Mt. Zirkel) in northwestern Colorado. A study was completed during the development of the Colorado Regional Haze SIP to compare CALPUFF predicted impacts for the Craig Station to IMPROVE data at Mt. Zirkel.[14] Modeled impacts for the Craig Station on the highest 25 days were compared against IMPROVE data, which includes impacts from all other sources (e.g., other point sources, area sources, mobile sources, etc.). The results showed that the modeled impacts from the Craig Station exceeded the monitored values on 14 out of 19 days, and in some instances by a significant amount. Given that the IMPROVE data reflects the cumulative impact of all sources, both within Colorado and outside of the state, the magnitude of the CALPUFF model over-prediction is severe. Although there is another large power plant located between the Craig Station and Mt. Zirkel, the modeled impacts from the Craig Station alone were larger than the monitored values for all sources combined, which further highlights the degree of over prediction. The modeled values were on average ten times the IMPROVE monitored values (i.e., 9.56 Mm^{-1}).[15]

5.3. NORTH DAKOTA SIP

In the development of the North Dakota Regional Haze SIP, the North Dakota Department of Health (NDDH) relied on photochemical modeling conducted by the Western Regional Air Partnership (WRAP) to determine the impact of sources located outside of the state, as well as non-utility sources in North Dakota.[16] CALPUFF was utilized to determine the impacts of utility sources within the state; however, NDDH utilized alternate options in the CALPUFF model to address known areas of inaccuracy. The specific areas where they deviated from the EPA BART prescribed approach include:

> Consideration of boundary conditions based on CMAQ modeling, rather than ignoring the impact of sources outside of the domain as is done in the EPA approach;

> Puff splitting;

> Diffusion coefficients based on actual measurements of turbulence rather than the 1952 Pasquill-Gifford diffusion confidents required by the EPA approach;

> Meteorological data from the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model; and

> Use of hourly average ammonia concentrations instead of an annual average value.

The resulting CALPUFF values were then compared to IMPROVE monitoring data from the South Unit at Theodore Roosevelt National Park, as summarized in Table 5-2 below.[17]

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[13] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[14] Gale Hoffnagle, Evaluation of Craig BART Modeling for Regional Haze Analysis, testimony before the Colorado Air Quality Commission, November 18, 2010.

[15] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[16] North Dakota State Implementation Plan, February 24, 2010.

[17] North Dakota State Implementation Plan, Chapter 8, February 24, 2010.

A review of extinction values showed that the average difference between measured and modeled extinction was 0.37 Mm^{-1} with a standard deviation of 12.6 Mm^{-1}.[18] EPA rejected NDDH's modeling on the basis that it included impacts from other sources rather than evaluating the impairment due to BART sources against the natural background visibility impairment ("dirty" background analysis vs. "clean" background analysis). EPA did not specifically comment on the accuracy of NDDH's CALPUFF modeling. Even with the revisions to the modeling methodology applied by NDDH, the margin of error was still 0.39 dv on average.[19]

Table 5-2. NDDH Measured versus Modeled Nitrate Concentrations

Theodore Roosevelt South Unit	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)
98th Percentile	2.03	2.06
90th Percentile	1.21	1.21
Average of 20% Worst Days	1.42	1.41
Annual Average	0.53	0.53

5.4. COLSTRIP GENERATING STATION

As briefly described above, TRC conducted an analysis of measured versus modeled visibility impacts for the Colstrip Station located in eastern Montana, which is partially owned and operated by PPL Montana, LLC. TRC specifically completed comparisons for the worst 20% measured days and worst 20% modeled days (where a corresponding measurement was available). The study found that CALPUFF significantly over predicted impacts from the Colstrip Station, as impacts from this source alone were frequently higher than the monitored values, which include all sources (e.g., point, area, mobile) as well as the Colstrip Station. Modeled nitrate extinction from the Colstrip Station alone was higher than the monitored values on 11 out of 22 of the worst 20% modeled days at the Theodore Roosevelt IMPROVE monitoring site. At the UL Bend Wilderness Area IMPROVE monitor, modeled nitrate extinction from the Colstrip Station exceeded the monitored values on 11 out of 28 of the worst 20% modeled days. At the North Absaroka IMPROVE site, the impact from the Colstrip Station was over predicted on 9 out of 20 days of the worst 20% modeled days. At the Yellowstone IMPROVE site there are 10 days when the modeled extinction from the Colstrip Station exceeded the monitored values for the worst 20% modeled days.

Based on this analysis, PPL Montana, LLC, the operator and partial owner, challenged EPA's BART analysis for Colstrip Station arguing that EPA could not "reasonably anticipat[e] as required by the [Clean Air Act]" the maximum predicted visibility improvement for Colstrip Units 1 and 2 because the incremental visibility improvement was within the model's margin of error.[20] The U.S. Court of Appeals for the Ninth Circuit concluded that EPA's response that low levels of visibility impairment must be addressed regardless of whether the visibility improvements are perceptible to the human did not resolve how EPA can reasonably anticipate visibility improvements within a model's margin of error.[21] Given the small magnitude of the CALPUFF predicted visibility improvements for Entergy's Lake Catherine Unit 4, Entergy similarly questioned whether EPA can

[18] These statistics are based on the exclusion of January 26, 2002 which was an outlier.

[19] [19] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[20] Montana Case, at 1146.

[21] *Id.*

reasonably anticipate visibility improvement from additional controls on the Lake Catherine Plant. As such, Trinity utilized a similar methodology to determine the CALPUFF margin of error specifically for the Lake Catherine analysis. Trinity's analysis is summarized in detail within Sections 4 *Modeling Methodology* and 5 *Results* of this report. As documented in the results section, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated* because the visibility improvements are within CALPUFF's margin of error.

6. CONCLUSIONS

Based on the analysis completed for the Entergy Lake Catherine Plant, the minimum calculated margin of error for CALPUFF for the Lake Catherine Plant is 0.93 dv. The CALPUFF predicted visibility improvements associated with EPA's proposed BART for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo fall within this margin of error. As such, the visibility improvements at each of these Class I areas associated with the proposed BART cannot be *reasonably anticipated*, as is required by the Clean Air Act.[22]

[22] 42 U.S.C. 7491(g)(2).

Entergy Arkansas Inc.

Comments on the Proposed Approval and Promulgation of Implementation Plans; Arkansas; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility

Docket No. EPA-R06-OAR-2008-0633

Submitted on:
August 5, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov

ENTERGY ARKANSAS INC.

COMMENTS ON THE PROPOSED APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS; ARKANSAS; INTERSTATE TRANSPORT STATE IMPLEMENTATION PLAN TO ADDRESS POLLUTION AFFECTING VISIBILITY

EPA-R06-OAR-2008-0633

I. INTRODUCTION

On July 6, 2015, the U.S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 38419, a proposed rule that would disapprove a revision to the State Implementation Plan ("SIP") submitted by the State of Arkansas on September 16, 2009, for the purpose of addressing the requirements of the Clean Air Act ("CAA") regarding interference with other states' programs for visibility protection for the 2006 revised 24-hour fine particulate matter ("$PM_{2.5}$") National Ambient Air Quality Standard ("NAAQS") ("Proposed Rule" or "Proposal"). Section 110(a)(2)(D)(i)(II) of the CAA, which EPA identifies as "Prong 4," requires that SIPs contain provisions to prohibit emissions from within the state from interfering with measures required to be included in the implementation plan for any other state under the visibility protection provisions of Part C of the CAA. EPA has interpreted this "good neighbor" provision as requiring states to include in their SIPs measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states. 80 Fed. Reg. at 38420. In addition to proposing to disapprove Arkansas' Prong 4 SIP submittal, EPA is proposing that the regional haze Federal Implementation Plan ("FIP") that the Agency proposed on April 8, 2015, *see* 80 Fed. Reg. 18944, remedies the deficiency created by the proposed disapproval of Arkansas' submittal.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA would regulate under the regional haze FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). As proposed, the regional haze FIP would impose Best Available Retrofit Technology ("BART") emission limits on White Bluff Units 1 and 2, the Auxiliary Boiler at White Bluff, and Unit 4 at Lake Catherine, as well as reasonable progress emission limits on Units 1 and 2 at Independence. As a result, EPA's proposal that the proposed regional haze FIP would satisfy Arkansas' Prong 4 obligation directly and significantly impacts Entergy.

In these comments, Entergy discusses its legal concerns with the Proposed Rule. Entergy appreciates EPA's consideration of these comments.

II. COMMENTS

A. Arkansas' SIP Satisfied Prong 4, Rendering Reliance on EPA's Proposed Regional Haze FIP Unnecessary.

EPA argues that Arkansas' SIP submittal fails to satisfy Prong 4 for two reasons. First, although Arkansas indicated in its SIP submittal that it complies with the Prong 4 requirement, it did not explain how it meets the requirement. 80 Fed. Reg. at 38421. Second, in 2012, EPA partially disapproved the SIP revision submitted by Arkansas in 2008 to address the regional haze requirements, including disapproving a large portion of Arkansas' BART determinations. *See* 77 Fed. Reg. 14604 (Mar. 12, 2012). As a result, EPA contends, the corresponding emission reductions from Arkansas sources upon which other states had relied in their regional haze SIPs would not take place. *Id.* EPA therefore proposes that its proposed regional haze FIP is necessary to address the requirement regarding interference with other states' programs for visibility protection for the 2006 $PM_{2.5}$ NAAQS. *Id.* at 38422.

Contrary to EPA's position, the Arkansas SIP submittal satisfies Prong 4, rendering the regional haze FIP unnecessary to address interference with other states' visibility SIPs. First, the SIP submittal does explain how it complies with Prong 4 by specifically identifying the state regulations that ensure emissions from Arkansas sources will not interfere with other states' regional haze SIPs. Second, while EPA has issued guidance documents stating that Prong 4 may be satisfied through the promulgation of a regional haze SIP, this is not the *only* way in which a state may meet its obligation. *See* Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards, at 9-10 (Aug. 15, 2006).[1] Indeed, EPA itself has acknowledged states may satisfy Prong 4 by something other than an EPA-approved regional haze SIP. 76 Fed. Reg. 8326, 8328 (Feb. 14, 2011) (Proposed Approval and Promulgation of State Implementation Plans; State of Colorado; Interstate Transport of Pollution Revisions for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS: "Interference With Visibility" Requirement).

In its SIP submittal, Arkansas indicated that Prong 4 was satisfied by (1) the EPA-approved Arkansas Pollution Control and Ecology Commission's Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Chapter 14; (2) A.C.A. § 8-4-311(a)(2), which authorizes ADEQ to advise, consult, and cooperate with other agencies of the state, political subdivisions, industries, other states, the federal government, and with affected groups to control or abate air pollution and to prevent new air pollution; and (3) A.C.A. § 8-4-311(a)(8), which authorizes ADEQ to represent the state in all matters pertaining to the plans,

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[1] Guidance issued after submittal of the Arkansas' SIP revision on September 16, 2009, similarly indicates that a regional haze SIP is not the exclusive way in which a state may demonstrate compliance with Prong 4. *See* Guidance on SIP Elements Required Under Sections 110(a)(1) and (2) for the 2006 24-Hour Fine Particle National Ambient Air Quality Standards, at 5-6 (Sep. 25, 2009); Guidance on Infrastructure State Implementation Plan Elements Under Clean Air Act Sections 110(a)(1) and 110(a)(2), at 34 (Sep. 13, 2013) ("A state air agency may elect to satisfy prong 4 by providing, as an alternative to relying on its regional haze SIP alone, a demonstration in its infrastructure SIP submission that emissions within its jurisdiction do not interfere with other air agencies' plans to protect visibility.") ("2013 Guidance").

procedures, or negotiations for interstate compacts in relation to air pollution control. Prong 4 SIP Submittal Attachment at 2.[2] This was sufficient to comply with Prong 4, because it identifies the regulatory mechanisms through which Arkansas works with other states to ensure that its emissions do not interfere with visibility efforts. Arkansas emissions cause and contribute to visibility impairment primarily in two Class I areas in Missouri, Hercules Glades Wilderness Area and Mingo National Wildlife Refuge, and potentially other Class I areas in Oklahoma, Kentucky, Illinois and Louisiana. Proposed Approval Regional Haze Interstate Transport SIP, 76 Fed. Reg. 64,186, 64,193, 64,215 (Oct. 17, 2011); Final Approval Regional Haze Interstate Transport SIP, 77 Fed. Reg. 14604, 14623 (Mar. 12, 2012). Of these states, only Missouri relied upon anticipated BART controls from sources in Arkansas when developing its regional haze SIP. *See* Missouri Regional Haze SIP, at 45 (June 25, 2009).[3] Subsequent to EPA's partial disapproval of the Arkansas BART limits, Missouri released a 5-Year Progress Report demonstrating that Mingo and Hercules Glades are on track to meet the 2018 visibility goals. Missouri Regional Haze Plan: 5-Year Progress Report, at 4, 17 (Aug. 29, 2014).[4] Missouri concluded that this progress was the result of emissions reductions at Missouri sources and that further reductions are not necessary. *Id.* at 1, 4, 17. Thus, Missouri has determined that no additional measures are needed in Arkansas to prevent Arkansas sources from interfering with Missouri's reasonable progress efforts.

B. EPA's Proposal to Rely on its Proposed FIP Is Premature and Violates the Notice and Comment Requirement.

EPA proposes to find that the requirements of Prong 4 will be satisfied by the combination of the emission control measures in the proposed regional haze FIP, and the already approved portions of the Arkansas regional haze SIP. 80 Fed. Reg. at 38422. It is inappropriate for EPA to propose such a finding when the Agency has not yet finalized its regional haze FIP. As EPA recognizes, the Agency cannot finalize this proposal unless and until it finalizes its action on the regional haze FIP. *See id.* Depending upon the comments submitted to EPA on the proposed FIP, the final regional haze FIP could be substantially different from the proposal. For example, Entergy intends to submit comments on the proposed regional haze FIP objecting to the proposed BART limits for White Bluff and the proposed reasonable progress limits for Independence. Entergy also has identified numerous legal and technical deficiencies in the proposed FIP, which will be discussed in detail in Entergy's comments on the proposed FIP.

It is impossible to know, during the comment period on this rulemaking, whether the final FIP will rectify these problems. Because significant changes could be made to the final FIP, because these changes are unforeseeable, and because Entergy has significant concerns that the final FIP may be legally and technically deficient, it is unreasonable to request public comment on a proposal that the final FIP will satisfy Prong 4. This is a clear violation of EPA's obligation under the Administrative Procedure Act to provide adequate notice and opportunity to comment on a proposed rule. 5 U.S.C. § 553. EPA should defer requesting public comment on this issue until after the Arkansas regional haze FIP has been finalized.

[2] Docket ID EPA-R06-OAR-2008-0633-0006.
[3] http://dnr.mo.gov/env/apcp/reghaze/moreghaze-09rev.pdf.
[4] http://dnr.mo.gov/env/apcp/reghaze/complete-RegionalHaze-5-yr-Rpt-submittal.pdf.

III. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed Rule. For the reasons explained in these comments, Entergy strongly urges EPA to approve the Arkansas Prong 4 SIP submittal. In the alternative, Entergy requests that EPA defer issuing a final rule until after (1) the final regional haze FIP for Arkansas has been issued, and (2) EPA has reopened the comment period for this Proposal to allow interested parties to comment on EPA's proposal that the final Arkansas regional haze FIP satisfies Arkansas' Prong 4 requirements.

Respectfully submitted,

Kelly M. McQueen
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Entergy Services, Inc.

Exhibit C

Sargent & Lundy LLC

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Date: November 22, 2016

Mr. Robert Fluth
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Entergy
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Dear Mr. Fluth

As requested by Entergy, Sargent & Lundy LLC (S&L) has reviewed the U.S EPA's Final Federal Implementation Plan for Regional Haze in the State of Arkansas ("Final FIP") as well as EPA's Response to Comment document ("RTC Document"). Despite S&L's comments to the Proposed FIP regarding the errors EPA made in assessing the cost-effectiveness to retrofit Dry FGD systems at White Bluff and Independence[1], EPA made no substantive changes in the final rule. As such, EPA's Final FIP continues to significantly underestimate the cost-effectiveness for these retrofit projects.

Although there were many issues associated with EPA's analysis, the primary factors that caused them to underestimate the cost-effectiveness were:

- Incorrectly calculating the tons of SO_2 removed by the dry FGD systems;[2]
- Annualizing the retrofit costs over a 30-year period, instead of the shorter period that will actually occur due to the future deactivation of these units; and
- Failing to consider updated costs provided by S&L in our comments to the proposed FIP

[1] *See* S&L, Review of EPA's Cost Analysis for Arkansas Regional Haze Proposed Federal Implementation Plan, Report SL-012913 (July 14, 2015)

[2] Instead of using average SO_2 emission rates during the baseline period to calculate emission reductions, EPA used the SO_2 emissions from the month with the highest SO_2 emission rate during the entire baseline period. As part of our comments, we suggested future emissions be calculated by multiplying the FIP emission rate by the average heat input during the baseline period, a method EPA has previously used and accepted. For example, in the final Federal Implementation Plan (FIP) for the Wyoming Regional Haze Program, EPA calculated annual NOx emission reductions by multiplying the controlled NOx emission rate (lb/MMBtu) by the baseline annual heat input for each unit (MMBtu/yr). See, 79 FR 5038-5041 (Tables 1 through 8). See also, Andover Technology Partners, "Cost of NOx Controls on Wyoming EGUs," October 28, 2013. Another example of EPA taking this approach is provided in the final Nebraska Regional Haze FIP (77 FR 40150), where EPA calculated potential annual SO_2 emission by multiplying the projected controlled emission rate (lb/MMBtu) by the baseline annual heat input. (77 FR 40157, Table 1). Similarly, in its approval of a "better than BART" alternative for the Navajo Generating Station, EPA calculated emissions for the various NOx control scenarios by multiplying the projected controlled emission rate (lb/MMBtu) by the baseline annual heat input (MMBtu/yr). See, 78 FR 62514. See also, Table 12 at 78 FR 8290 (Proposed Rule) and the document titled "BART Alternatives.xlsx" in the Navajo Generating Station Regional Haze docket at EPA-R09-OAR-2013-0009. Had EPA used average SO_2 emission rates instead of monthly maximum values, this would have been equivalent to our approach.

To address some of EPA's questions raised in its proposed FIP regarding costs, S&L submitted a cost report[3] as part of our comments, but EPA's Final FIP did not consider this document and estimated the total capital investment for installing dry FGD at White Bluff Unit 1 and 2 to be $495,074,600. By not considering our 2015 Cost Report, EPA failed to correct significant errors made in its cost analysis, including but not limited, to: 1) excluding Balance of Plant ("BOP") costs that were incorrectly assumed to be double-counted; 2) underestimating escalation by relying upon cost indices instead of more accurate information from equipment vendors; 3)incorrectly calculating O&M costs; 4) adjusting capital costs to a fuel-sulfur basis that is inconsistent with industry practice for FGD equipment design[4]; and 5) excluding certain projects costs such as AFUDC and owner's costs. The errors that EPA made when estimating dry FGD costs at White Bluff were compounded when EPA applied them to the Independence units as part of its Reasonable Progress determination.

A primary reason that EPA gave in its RTC document for rejecting many of S&L's comments and our 2015 Cost Report was that the 2009 and 2013 Alstom quotations were not made available to EPA. As part of its petition for reconsideration, Entergy is supplying the relevant sections from both the 2009 and 2013 Alstom quotations to enable EPA to confirm that the scope and pricing adequately supports our comments and 2015 Cost Report.

We note that upon further review of the Alstom quotations, S&L inadvertently double-counted the portion of ductwork downstream of the booster fans in our 2015 Cost Report, so we have revised our cost estimate to eliminate the double-counting. The table below compares the total capital investment for White Bluff 1 and 2 dry FGD projects that we provided in our 2015 Cost Report to the revised costs. Although we believe AFUDC, escalation and owner's costs to be real costs that would be incurred by these retrofit projects, this table also shows the total capital investment excluding those items.

Total Capital Investment for Dry FGD at White Bluff 1 and 2	$2015
2015 Cost Report	$ 1,072,370,000
Revised Costs[5]	$ 991,489,000
Revised Costs Excluding AFUDC, Escalation and Owner's Costs	$ 729,667,000

The resulting cost effectiveness based on the revised costs and corrected tons of SO_2 removed are calculated below assuming a remaining useful life of 6 or 7 years for either White Bluff Unit 1 or 2.

[3] *See* S&L, White Bluff Dry FGD Cost Estimate and Technical Basis, Report SL-012831, "2015 Cost Report" (July 14, 2015).
[4] EPA used 30-day average fuel sulfur levels, 0.68 lb SO_2/MMBtu, as its basis for dry FGD capital cost estimates at White Bluff because compliance is averaged over a 30-day period. In our comments, we showed that White Bluff historically has fired fuels containing sulfur levels up to 1.2 lb SO_2/MMBtu. Therefore, S&L set the capital cost fuel sulfur basis for this equipment at this level because these fuels may be fired over longer durations. Our approach is consistent with industry practice and has been utilized by S&L in all of our FGD retrofit projects. Regardless of whether we agree with EPA's claim that this practice does not preserve the integrity of the cost-effectiveness calculation, which we do not, EPA failed to account for a scenario in which Entergy might fire 1.2 lb SO_2/MMBtu fuels consecutively for two years and then fire 0.2 lb SO_2/MMBtu fuels consecutively for three years. In this example, although not required by Regional Haze, the average fuel sulfur levels would be consistent with those from the 5-year baseline period and thus satisfy EPA's arbitrary criteria of preserving the integrity of the cost-effectiveness calculation; however, the FGD equipment supplied in EPA's capital cost estimate based on 0.68 lb SO_2/MMBtu fuels would not achieve the required outlet emission rates for the first two years of operation in this example.
[5] Cost line item 111 "Flue Gas System" shown on page 11 in Attachment 1 of SL-012831 was updated to remove the ductwork design, supply and construction costs; however, foundation and insulation costs remain in the BOP scope of work.

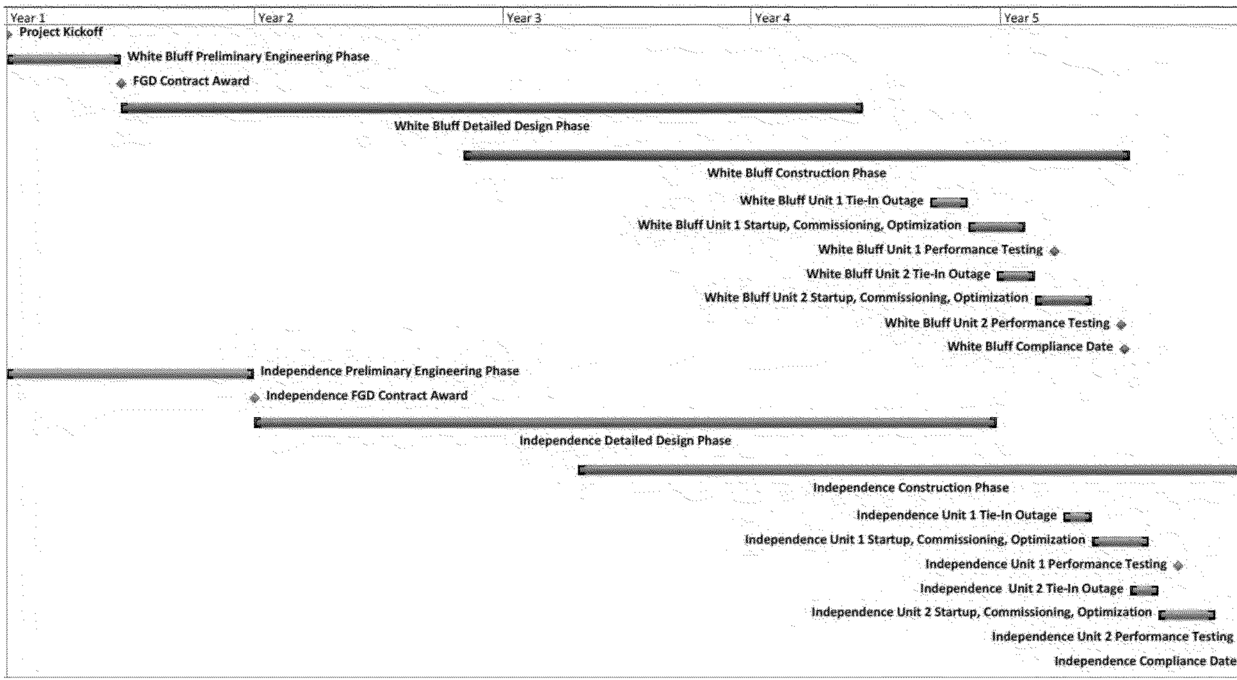
Cost Effectiveness for Dry FGD at White Bluff 1 and 2	White Bluff Unit 1 ($2015)		White Bluff Unit 2 ($2015)	
	2027	2028	2027	2028
Remaining Useful Life (years)	6	7	6	7
Capital Recovery Factor	0.2098	0.1856	0.2098	0.1856
Annualized Capital Cost (S&L Revised Costs)	$104,007,196	$92,010,179	$104,007,196	$92,010,179
Annualized Capital Cost (Excluding AFUDC, Escalation and Owner's Costs)	$76,542,068	$67,713,098	$76,542,068	$67,713,098
Total Annual O&M Cost	$10,166,000	$10,166,000	$10,166,000	$10,166,000
Baseline Emissions (tons)	15,939	15,939	16,034	16,034
Controlled Emissions (tons)	1,675	1,675	1,681	1,681
Emissions Removed (tons)	14,264	14,264	14,353	14,353
Cost Effectiveness – S&L Revised Estimate ($/ton)	$8,004	$7,163	$7,955	$7,119
Cost Effectiveness – Excluding AFUDC, Escalation and Owner's Costs ($/ton)	$6,079	$5,460	$6,041	$5,426

As EPA found in the rule, installing a single new FGD system typically takes up to five years (60 months). Because the rule's new and more stringent emission limitations become effective on October 27, 2021 Entergy will need to initiate the dry FGD projects immediately to ensure all four units can achieve the new requirements in the time allotted.

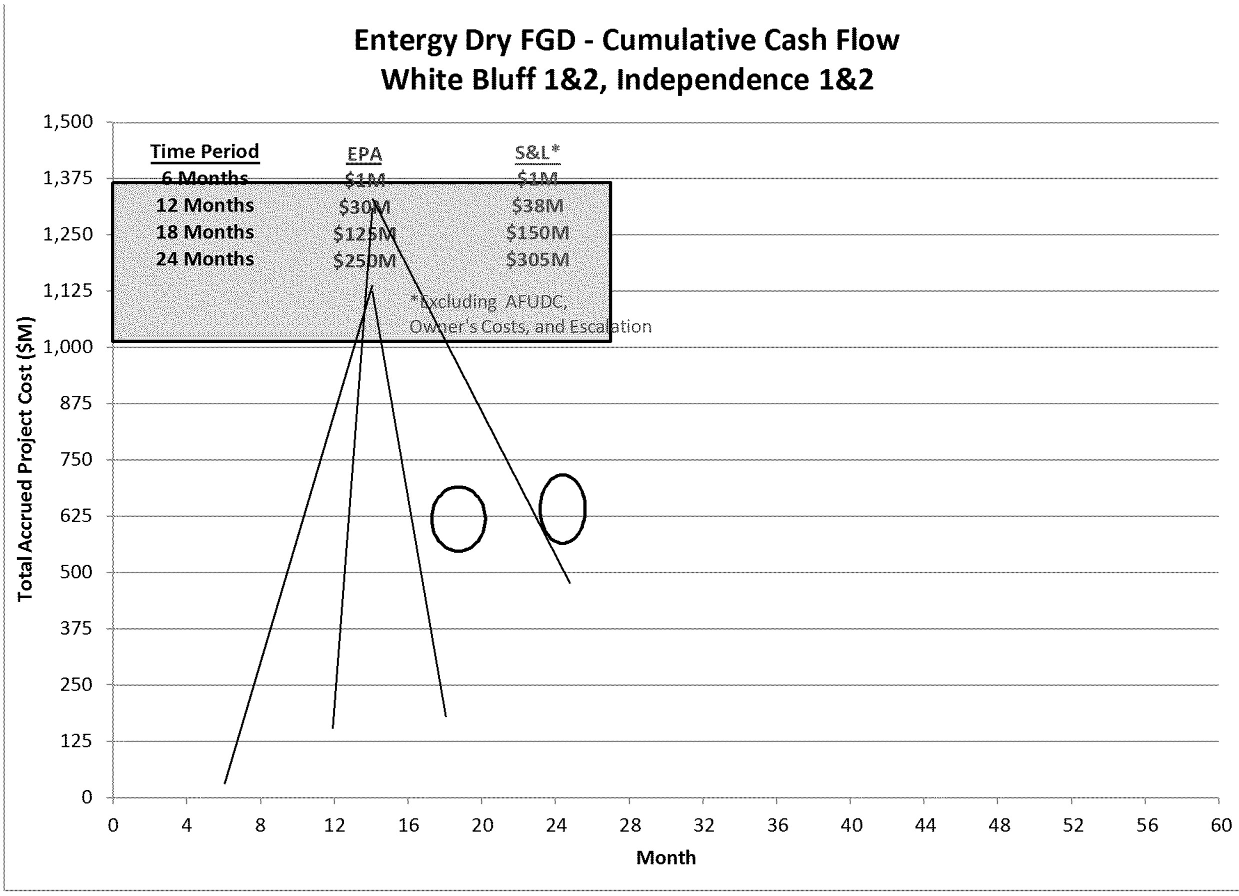
Major air quality control retrofit projects such as these consist of three main phases: 1) preliminary engineering; 2) detailed design; and 3) construction. During the preliminary engineering phase, Entergy will need to work with an engineer to develop detailed specification requirements for the engineering, procurement, and construction of the FGD systems. Contractors will need at least three months to develop proposals, and then several weeks will be required to evaluate the proposals and award the contract. The preliminary engineering phase is typically between 6 to 12 months in duration. Because no preliminary engineering has been conducted at Independence, the preliminary engineering duration for this station is expected to be closer to a year to fully define the scope and to prepare and award the FGD contract. In addition, because White Bluff and Independence have different co-owners, two separate FGD contracts will need to be developed. After award, the FGD contractor at each station will proceed with the detailed engineering phase, during which every component required for a complete and operable FGD system will be designed and fabricated.

During the construction phase, the engineered components will be delivered to site and the FGD contractor at each site will erect them and integrate them into the existing plants. A tie-in outage must be taken to shut the units down so that physical connections to existing systems can be made. Because Entergy would not take simultaneous outages at all four units and because there will be two FGD contracts awarded at different times, the construction phase will likely be staggered by approximately one year across all four units.

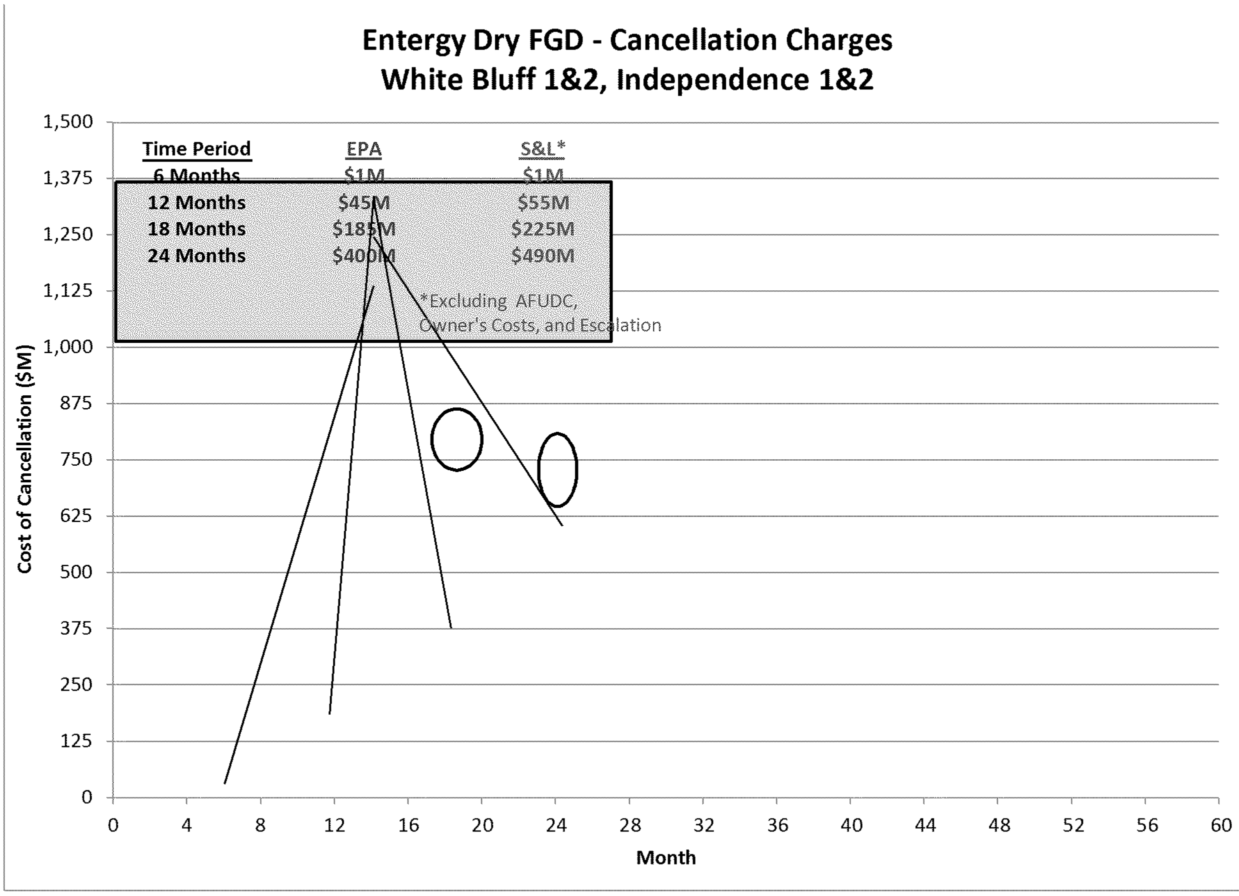
Once constructed, equipment startup and commissioning will occur, followed by operational tuning and performance optimization before performance testing is conducted to confirm compliance with emission targets. The FGD contractor will need a total of approximately three years to complete engineering and construction of one unit, followed by up to six months of commissioning, startup, performance optimization, and performance testing. The following project schedule reflects the phases and durations described above and is representative of the schedule Entergy would need to adhere to in order to meet the compliance date of October 27, 2021 for all four units.



The following graph represents the cumulative payments, or cash flow, during the three project phases for all four dry FGD projects based on the above schedule. This graph compares the minimum cash flow expected based on EPA's cost analysis (red), to the cash flow that would be expected based on S&L's capital cost estimate, excluding AFUDC, escalation and owner's costs (blue). This graph thus illustrates a reasonable range Entergy would need to invest after 6, 12, 18, and 24 months starting from the effective date of the FIP.

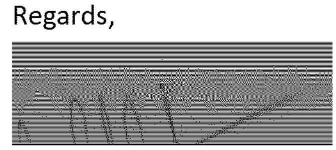


Furthermore, if it is later determined that Entergy is not required to install FGD systems on these units, then cancellation charges would be incurred as part of the FGD contract. The following graph represents the cumulative cancellation charges that would likely apply based on the project schedule. This graph compares the minimum cancellation charges expected based on EPA's cost analysis (red), to the cancellation charges that would be expected based on S&L's capital cost estimate (blue), excluding AFUDC and owner's costs. This graph thus illustrates a reasonable range for cancellation charges that would apply to Entergy after 6, 12, 18, and 24 months starting from the effective date of the FIP.



Based on the above graphs and depending on whether and when Entergy's petition for reconsideration is granted, Entergy is expected to incur costs of at least between $ 150 million and $305 million and possibly more than $490 million in the next 24 months.

Regards,



Andrew J Carstens
Vice President

Exhibit D

Exhibit Contains Confidential Business Information and Is Not Included

Exhibit E

Exhibit Contains Confidential Business Information and Is Not Included

Exhibit F

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11/22/2016

Attn: David Triplett

Amec Foster Wheeler Proposal No. 65-142232-00 Rev. 2

Reference: Entergy White Bluff/Independence - NOx Limitations at Reduced Load

Dear Mr. Triplett,

The following is intended to explain the limitations and issues associated with NOx reduction at reduced load, specifically below 50% of Maximum Continuous Rating (MCR).

First, it is important to understand how NOx is created in boilers and how specific boiler designs can result in increased NOx emissions at reduced load.

NOx Formation

There are two common mechanisms of NOx formation, thermal NOx and fuel NOx. Thermal NOx refers to the NOx formed through high temperature oxidation of nitrogen found in combustion air. The rate at which airborne nitrogen converts to NOx is a strong direct function of temperature and residence time at temperature and is generally known to contribute on the order of 20% of boiler exit NOx.

NOx is also formed from nitrogen in the fuel. When a carbon based fuel such as coal is burned, the elemental nitrogen is exposed to oxygen at high temperature converting it to NOx. Laboratory studies indicate that fuel laden nitrogen contributes approximately 80% of boiler exit NOx in boilers without firing systems designed specifically with NOx emissions in mind.

Regardless of origin, whether from air or in fuel, nitrogen will convert to NOx when temperatures exceed 2000°F in the presence of oxygen. Low NOx firing systems are therefore designed to minimize the duration and magnitude of peak flame temperatures in excess of this value while also keeping local levels of oxygen to a minimum.

Current NOx Emissions

Consider Figure 1 below, which is the NOx data reported to the EPA for Entergy White Bluff Unit 1 for the period from June 2015 to June 2016.

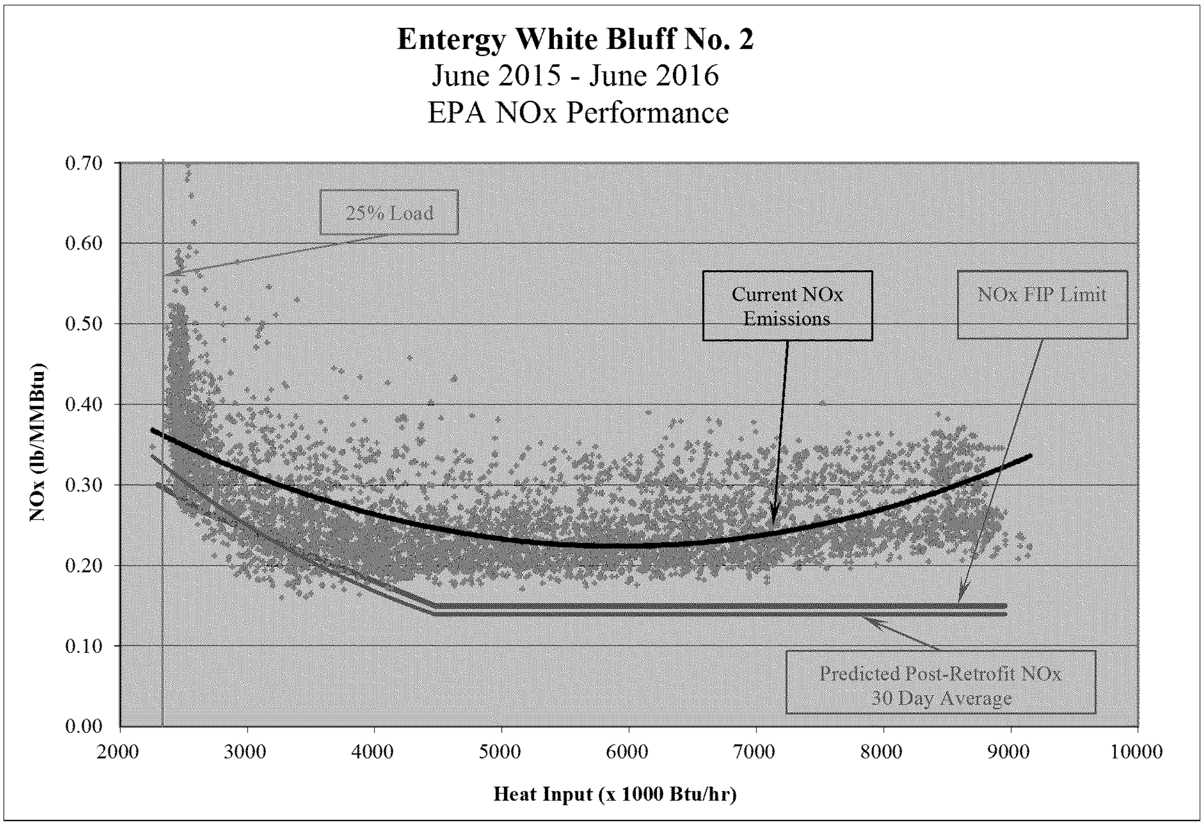

Figure 1 - EPA NOx Emissions for White Bluff No. 1

The scatter data plotted above is the hourly input provided to the EPA over the past year; the black line is the average of that data. The red line represents the NOx limit required by the Arkansas Regional Haze Federal Implementation Plan across the range from 25 to 100 percent heat input, which is 0.15 #/MMBtu from 50 to 100% of maximum load and 671 lb NOx/hr (3-hour average) from 25 to 50% of maximum load ("NOx FIP limit").

The curve exhibits a NOx trend that is typical of tangential (or corner-fired) boilers across their load range. Specifically, the amount of NOx formed is fairly level from 50% (4,475 MMBtu/hr) to 100% heat input (8,950 MMBtu/hr) as a function of firing rate. However, below 50% heat input NOx levels increase as a percent of heat input, trending upwards as load is reduced.

The heat input at less than 50% load is substantially reduced so the increase in NOx does not come from nitrogen in the fuel, but from an elevated conversion of air laden nitrogen. This is largely an expected phenomenon because boilers firing at low loads use increased levels of excess air to keep boiler operation safe. Additionally, to keep boiler operations safe during load swings, control systems always lead load increases with air flow first and follow load decreases with reductions in air flow last. This control logic results in excess air above set point during all load swings, contributing further to NOx formation, especially at low loads.

Proposed NOx Control Solution

Entergy proposes to install low-NOx burners and separated overfire air on all four White Bluff and Independence boilers to reduce NOx emissions across the load range. Most suppliers will guarantee

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performance of the overfire system across the load range from 50-100%; this range is typically known as the control range and is the range where overfire air is considered safe for use in reducing NOx.

Overfire air systems are based on the application of secondary air staging technology commonly referred to as "overfire air". Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is normally reduced by more than 50%.

The systems being installed at White Bluff/Independence will feature the addition of a single level of separated overfire air to the boilers which already have overfire air in the main windbox.

White Bluff No. 1 Reheat Temperature Control

Most steam generator or boiler manufacturers use an increased amount of (excess) air in their boilers at reduced load to maintain steam temperatures.

However, tangential-fired boilers have a second unique method for controlling reheat steam temperature across the load range of the boiler. Specifically, the coal burners and secondary air nozzles can tilt vertically up or down from a horizontal position by 30 degrees. A downward tilt pushes the fireball lower in the furnace which increases furnace thermal absorption and reduces furnace exit gas temperature (FEGT). The converse is also true: tilting the coal burners upwards in the furnace increases the furnace exit gas temperature.

Based on Figure 1, it is apparent at reduced load that the increase in overall NOx is due to an increase in thermal NOx. This increase is being caused directly by main windbox tilt position, (most likely above horizontal to control reheat temperature), high excess air, and mills in service (upper elevation mills in service results in higher FEGT).

NOx Control at Reduced Load

When installed, overfire air systems are optimized for operation across the load range. The following is a typical curve for an overfire system installed on a tangential-fired boiler.

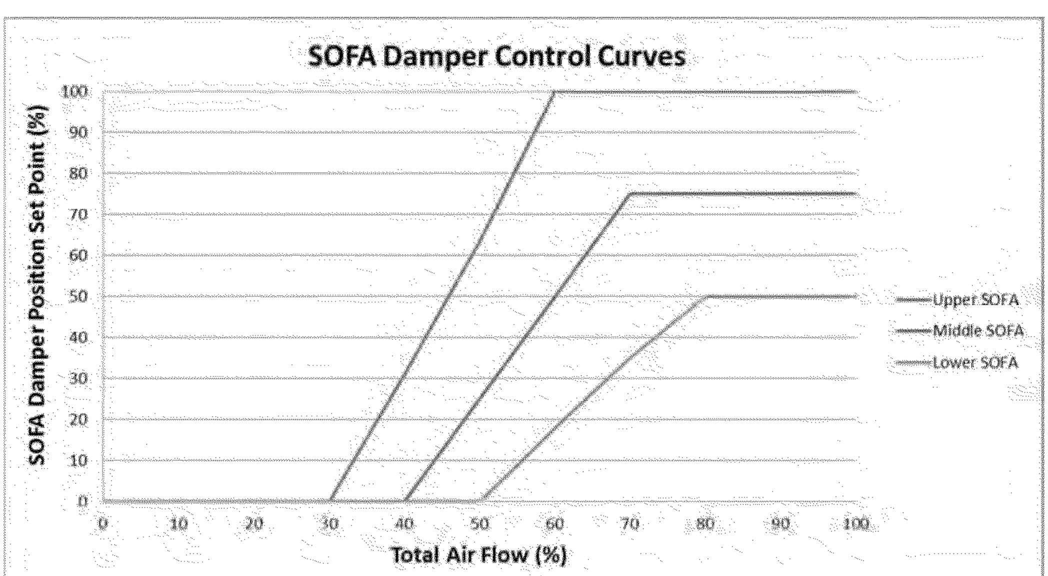

Figure 2 - SOFA Damper Control Curve

As can be seen from above, no overfire air is introduced to the boiler below 30% boiler load. This is because at reduced load, there is insufficient air to support both good combustion and maintain overfire air flow to the boiler. This means that the overfire system below this point does not provide any NOx reduction.

It should be noted here that the rate at which NOx is generated between the load points of 20 and 30 percent heat input is 2.38 times the rate between 30 and 50 percent. To alleviate issues with low load operation, the limit should increase from 671.25 #/hr to 895 #/hr. This change, which is reflective of the issues of instability at low load where separated overfire air is not available to use for NOx control, would then result in an FIP limit curve as shown in red below in Figure 3.

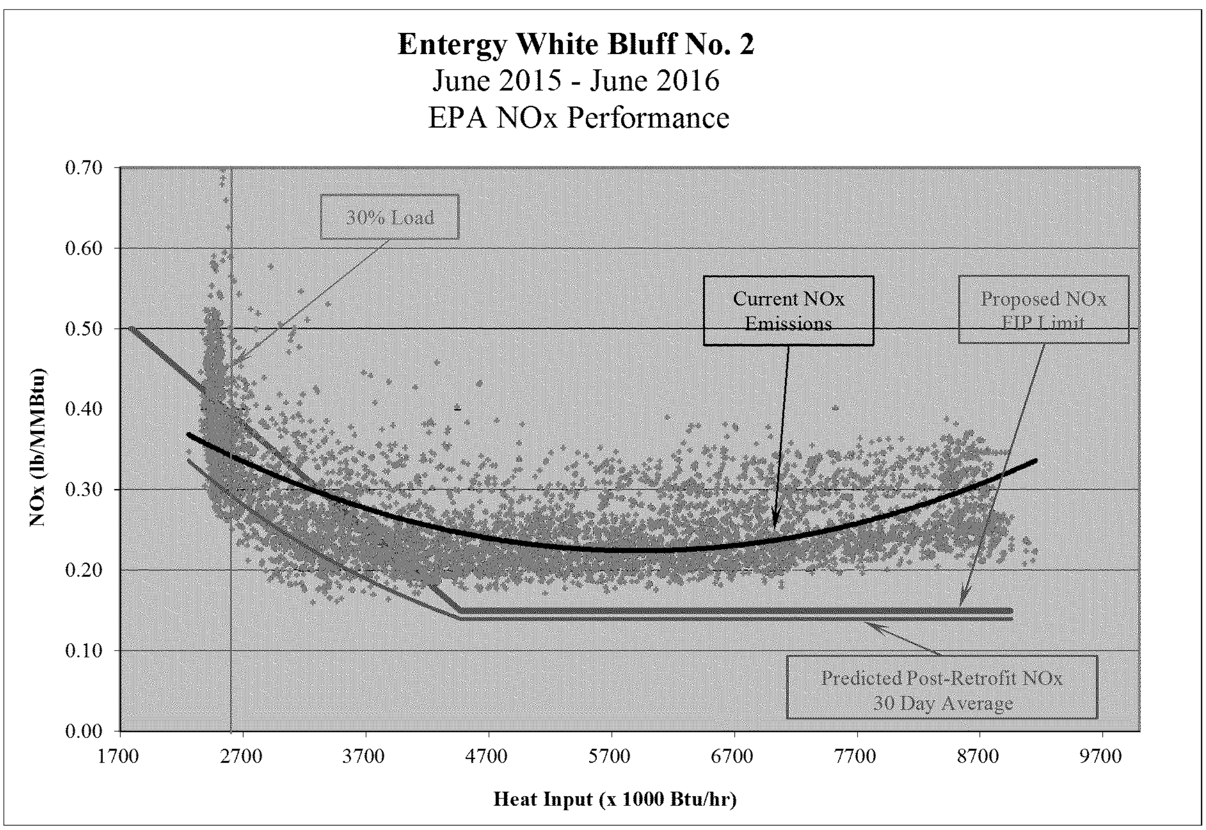

Figure 3 - NOx Generation at < 30% Load

With no overfire air system available to reduce NOx, the NOx reduction strategy at reduced load focuses on the direct causes of increased NOx: namely, up-tilt of the burner nozzles and high levels of excess air.

1.) Up-tilt of Coal Burners

To reduce NOx, the current burner tilts would have to be lowered below horizontal. This will reduce NOx emissions but will also result in reduced steam temperatures, causing a loss in boiler efficiency.

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2.) Excess Air

The current boiler excess air levels would be reduced to promote NOx reduction. Again, as with the burner tilts, this change will result in lower steam temperatures and reduced boiler efficiency.

All of these parameters will be optimized during the tuning process with the expectation of running with lower excess air levels and with tilts closer to horizontal. These factors alone will significantly reduce NOx at this load, which is important because the NOx reduction from the Tangential Low NOx TLN system will be minimal due to a low mass flow of overfire air.

NOx and Variable Load

NOx concentrations remain relatively flat during periods of steady-state operation. However, during periods of load transition, and in particular at reduced load, NOx is very sensitive to changing conditions such as air flow; fuel flow and burner tilt position. When load is being ramped up or down, and mills are put in or out of service, NOx can spike to levels well above permitted values for short periods of time. Within minutes of the excursion, NOx will typically return to and stabilize at the steady state level.

However, the issue lies with the duration of the reporting period: if the period is short (3-hours), the excursion in NOx (which may last only 15 minutes) will result in an exceedance over the permitted 3-hour value as the spike in NOx will not be averaged out by lower NOx values achieved for the remaining 165 minutes. See Figure 4 below for an illustration of this time period.

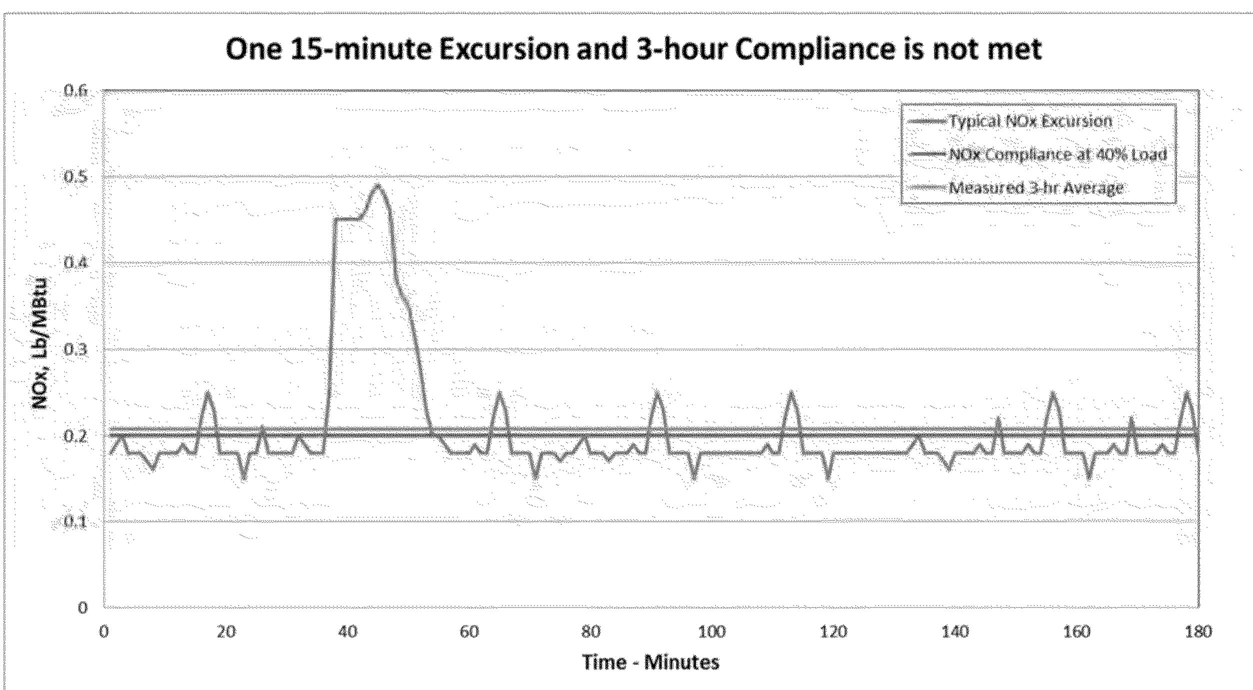

Figure 4 - 3-hour NOx Reporting Period

If the reporting period is longer, such as for the 30-boiler-operating-day limit for the high-load limit (50-100%) of the final FIP, then the occasional spike in NOx due to load transition can be accounted for by the majority of the reported NOx data being below permitted values. Figure 5 illustrates the impact of this longer reporting period.

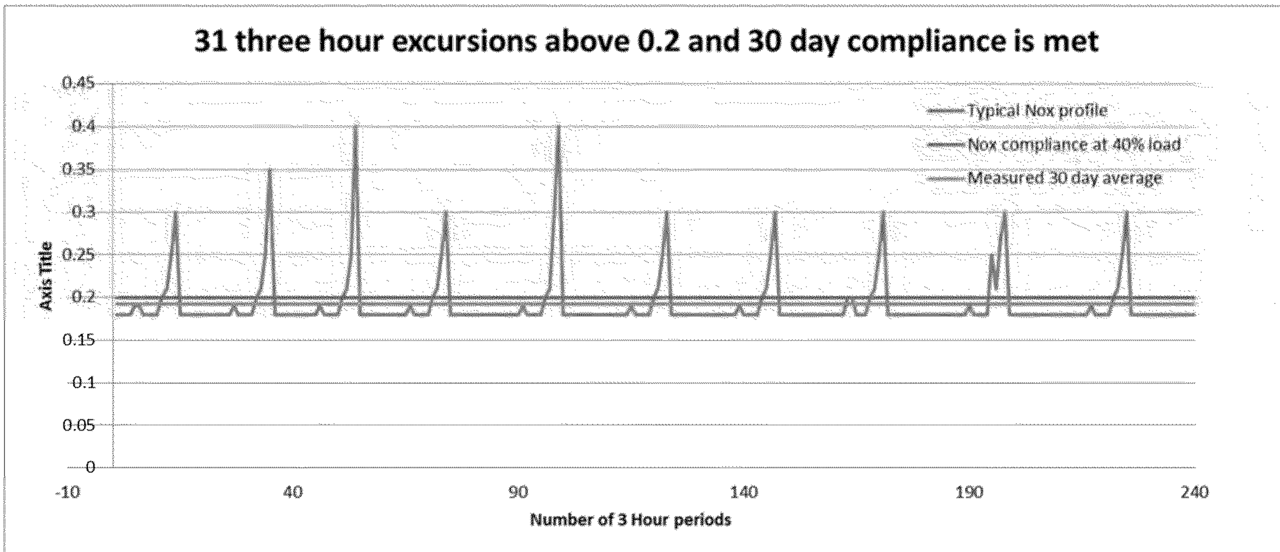

Figure 5 - 30-Day NOx Reporting Period

Boiler Start-up

A systematic approach is required for the start-up of any boiler that has been out of service for a period of time. These approaches can vary depending on the boiler design, but all approaches are based on the same premise: safe start-up procedures that prevent damage to the equipment and ensure personnel safety.

To ensure safe start-up, certain procedures are in place: these include support fuel to ensure ignition of the coal, high excess air to promote stable combustion and up-tilt on the coal burners to push the combustion zone upwards in the furnace and promote an appropriate rise in temperature and pressure.

The National Fire Protection Agency (NFPA) also recommends that, on boilers fitted with overfire air systems, the "boiler shall be operating in a stable manner before the overfire is introduced." This means that during boiler start-up, the overfire system is not in service and NOx is predominantly uncontrolled.

Unfortunately, all of the procedures in place to promote a safe boiler start-up are parameters that adversely impact NOx. It is not until stable combustion is achieved and the overfire air system is put into service that NOx can be controlled on a continuous basis.

Summary

Operation: Maintaining compliance at loads below 50% heat input will be difficult primarily due to the short reporting period. If compliance becomes troublesome, then following implementation of the NOx FIP limit, Entergy may have to institute new operating procedures that limit ramp rates or otherwise deviate from OEM recommended boiler operating practices. As has been stated, NOx control below 50% will be difficult, especially during boiler start-up and load swings, as the new overfire air system will be limited in its effectiveness because secondary air will almost entirely be directed to the main windbox for safe unit operation.

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Reporting Period Duration: The swings that are normative at reduced load make the permitting levels difficult to achieve in short reporting periods. A single 15-minute spike in NOx could result in NOx exceeding the permitted level in a 3-hour reporting period, even if the remaining 165 minutes are under compliance levels.

In the case of a longer reporting period, e.g. 30 - boiler operating days, these same NOx spikes seen during load transition can be accommodated and NOx levels can be maintained below required reporting levels.

If you have any questions or require further information, please do not hesitate to contact Steve deMello (office: 908-713-2281) or myself.

Sincerely,

Kenneth McCarthy
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